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Chapter 1

INTRODUCTION

The California Public Utilities Commission's December 20, 1995, decision on electric industry restructuring (D.95-12-063 as modified by D.96-01-009), referred to in this report as “the Decision,” provides for the establishment of an enforceable “minimum renewables purchase requirement (MRPR)” within the overall resource mix supplying California’s electricity. In its restructuring decision (p. 147), the Commission states a “commitment” to establishing policies that maintain California's resource diversity for existing resources and encourage the development of new renewable resources.

A Renewables Working Group formed on an ad hoc basis early in 1996 to address the major issues involved in the implementation of the California Public Utilities Commission’s (CPUC) renewables policy. The group has been meeting on a biweekly basis ever since, with a growing attendance that includes representatives from the renewable power industries, the major private and public electric utility companies in the state, state agencies, and consumer and environmental advocacy groups. A list of Working Group participants is included in Appendix E. The Working Group has defined the major points that a comprehensive renewables program will have to address, and has debated the many approaches advanced for the design of the program. This dialogue has led to a better understanding on the part of all parties about how a program can be structured to work.

The CPUC Renewables Working Group parties are submitting the Renewables Working Group report coincident with the August 1996 Industry Restructuring Hearings held by the California Electric Industry Restructuring Legislative Conference Committee (Senator Steven Peace, Chairman). Many members of the CPUC Renewables Working Group are also involved in the Legislative Hearings. The Renewables Working Group report represents the parties’ best efforts before the completion of the legislative process. As such, Renewables Working Group parties’ comments or positions expressed in this report may be modified as a result of the ongoing legislative process.

From the beginning, it was acknowledged that no one approach to developing a renewables policy to implement the Commission’s restructuring decision would be agreed to by all participants in the Working Group. The Working Group invited all interested parties to submit comprehensive program proposals for the implementation of the CPUC’s renewable energy policy. The Working Group specifically requested ***comprehensive program*** proposals in order to avoid a circumstance in which it would have a collection of limited-purpose proposals addressing a variety of pieces of a renewables program, but no way to understand how the pieces would fit together into an integrated, total program. The group has received six comprehensive program proposals from participating parties. Five of the six comprehensive proposals present strategies for the implementation of a program based on the

MRPR approach. The sixth proposal is for a surcharge-funded program that distributes renewable production credits on the basis of a competitive bidding process. The Working Group also received two adjunct proposals that seek to support specific types of technologies within the context of whatever overall renewables program is adopted. The eight proposals provide a variety of approaches to the development of a workable renewables policy for California, and illustrate the range of issues that must be addressed in formulating the program.

The Working Group acknowledges that a determination of the costs and benefits of various proposals would be desirable. However, after discussion, Working Group members decided that a meaningful cost/benefit assessment would be too complex and too difficult to achieve within the group.

Section A of the first chapter of the Renewables Working Group report includes a brief review of the existing legal and regulatory framework within which the policy must fit. Section B summarizes the Commission’s renewables policy as articulated in the December 20, 1995 decision on restructuring, and the follow-up roadmap decision. Chapter 2 presents abstracts of the six comprehensive program proposals and the two adjunct proposals that have been received by the Working Group. Chapter 3 considers some of the commonalities and differences among the proposals, and highlights areas of broad group consensus. The full proposals are presented in Chapter 4 of the report. Each proposal provides answers by the proposal sponsors to all of the implementation questions that are listed in Appendix C. These questions were identified in the Decision, and augmented by the Working Group. Each proposal is followed by a series of one-hundred word statements submitted by Working Group participants commenting on the proposal, and indicating whether that party supports or opposes the proposal with reasons for their positions. Appendix A contains electric production and renewables data in response to the Commission’s request in the Roadmap Decision (pg. 31, D.96-03-022). This appendix provides statewide data and aggregated investor-owned utility (IOU) data. Appendix B supplies IOU-specific data on renewables production. Appendix D contains a list of acronyms used in this report.

A. Existing Law and Regulations

The Commission and the California State Legislature have indicated that renewable resources provide environmental and fuel diversity benefits to California. Under Public Utilities Code Section 701.1(a), "a principal goal of electric . . . utility resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment and to encourage the diversity of energy sources through . . . development of renewable energy resources, such as wind, solar, biomass, and geothermal energy." In calculating the cost-effectiveness of energy resources, the Commission is directed under Section 701.1(c) to include a value for any costs and benefits to the environment, including air quality. Section 701.4 makes it state policy for electric resource acquisition programs to recognize and include a value for the resource diversity provided by renewable resources. The Commission is further directed to set aside a portion of electric capacity needed for California renewable resources until it "completes an electric generation procurement methodology that values the environmental and diversity costs and benefits associated with various generation technologies." (Section 701.3) The Commission has indicated that portions of the California public utilities code may change as restructuring proceeds.

In its restructuring decision, the Commission noted that the present mix of renewables on the system was driven by resource diversity interests on the part of utilities and the Commission's implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA), which encouraged the growth of independent power production in general, and renewables in particular, during the 1980s. It is important to note that the existing laws and regulations, as well as the existing renewable energy industries in the state, developed within the context of the regulated monopoly utility structure that still is in effect. The challenge is to create a program that will allow the renewable energy industries to adapt to a restructured electric utility environment based on the principle of competition.

B. Commission Goals for Renewables in Restructuring

In its restructuring decision, the Commission stated its "commit[ment] to establishing restructuring policies which maintain California's resource diversity for existing resources as well as encourage development of new renewable resources" (D.95-12-063 as modified by D.96-01-009, p. 147). The Commission also indicated a need to find policy mechanisms for the achievement of societal goals, many mandated by the state legislature, that do not put utilities at a disadvantage in the move toward a more market-based electric services industry (ibid. p. 145). These policies are to be consistent with the overall goals of restructuring, which includes placing “sustainable, downward pressure on the cost of electricity to all classes of California ratepayers.”

To meet these goals, the Commission proposed “the establishment of a target level of generation from renewable resources. This target will be backed by a meaningful penalty for noncompliance” (ibid. p. 146). Later, the decision states that the Commission “continues to believe that a minimum renewables purchase requirement is the best approach to meet our resource diversity goals” (ibid. p. 150-151). The Commission noted that it would be a "condition of certification" for all obligated entities. "We prefer that the requirement be set at the same level for all electric utilities on a statewide basis, but recognize that it may be appropriate to develop a transitional strategy given the current resource portfolios of some utilities" (ibid. p. 150). Credits for meeting this requirement would be tradable "in order to allow retail providers the most flexibility in meeting this requirement." The Commission indicated that it "may be appropriate to establish floors for certain technology types, in order to maintain the diversity of our renewable resources" (ibid. p. 151).

The Commission noted that the market-based approach "will allow buyers and sellers to search the market for the best renewables bargains and to internalize such costs in their prices without the need for a surcharge to fund renewables development. Establishing a surcharge to fund new renewables development would require some sort of prescribed allocation mechanism or bidding procedure to disperse the funds. We could use an administrative approach to ensure compliance, but after our experience in the BRPU we are hesitant to do so. The minimum renewables requirement approach will allow the market to provide the most cost-effective renewable resources, without our intervention" (ibid. p. 151).

In terms of timing, the Commission stated that “we would expect that these minimum renewables levels would be in place beginning in 1998 and continuing through 2000, at which point we would revisit whether the requirement should be modified.” With respect to stranded costs, the Commission also stated: “Allowing providers to trade in order to meet the renewables requirement may also serve to minimize the stranded costs associated with existing Qualifying Facility (QF) contracts by providing new markets for QFs’ power” (ibid. p. 151).

Chapter 2

PROPOSAL ABSTRACTS

The Renewables Working Group has received six comprehensive program proposals and two adjunct proposals for strategies to implement the renewable energy policy embodied in the CPUC's December 20, 1995 decision on restructuring of the electric utility industry. The proposals offer a variety of strategies to achieve the CPUC's objectives for renewable energy, and illustrate the range of approaches that can be taken to develop a program for the promotion of renewable energy sources within the context of a deregulated market for electricity generation. Five of the six comprehensive proposals involve some sort of minimum renewables purchase requirement. The sixth comprehensive proposal offers renewable generators that add electric production to the grid an auctioned surcharge funded production credit. The two adjunct proposals are aimed at promoting targeted emerging renewable energy technologies within the context of any of the comprehensive implementation programs by providing an additional incentive to accelerate full commercialization.

Sponsors submitted the following brief abstracts outlining the key points of their proposals. Full proposals and parties' comments are contained in Chapter 4.

A. Comprehensive Program Proposals

1. Proposals with a Minimum Renewables Purchase Requirement

a. Renewables Portfolio Standard

Submitted by: The American Wind Energy Association (AWEA), California Biomass Energy Alliance (CBEA), Geothermal Energy Association (GEA), Solar Thermal Energy Alliance (STEA), Union of Concerned Scientists (UCS),California Integrated Waste Management Board (CIWMB)

This proposal is for a minimum purchase requirement of renewable electricity to be applied equally to all retail sellers of electricity under the Commission's jurisdiction and, with legislation, on all retail sellers statewide. The definition of renewables is limited to wind, solar, geothermal, solid fuel biomass, biogas, and solid waste-to-energy. The proposal, termed a "Renewables Portfolio Standard" (RPS), is designed to preserve the existing level of renewable energy generation serving the state by requiring that all retail sellers include a minimum of 11.6% renewable energy (kWh) in their sales, demonstrated by ownership of tradable "Renewable Energy Credits." The percentage requirement is proposed to gradually increase consistent with past Commission decisions. Within the 11.6% requirement is a 2.1%

requirement for electricity generated by solid fuel biomass, demonstrated by ownership of tradable "Biomass Energy Credits." The separate technology band for solid fuel biomass reflects the desire to preserve the substantial and unique environmental benefits of this industry that stem from its use of biomass fuel, and its higher cost of electricity generation due to the same cause. The cost of renewable and biomass energy credits is capped at a level somewhat above the expected cost of these credits. Importantly, the price cap method does not undermine the market competition.

This strategy builds in competition among renewables by beginning the obligation at a level slightly lower than the electricity delivered by renewable generators in 1993, and by the competitive procurement of renewable energy credits by retail sellers. The regulatory role is limited to certifying these credits, verifying that retail sellers possess the required number of credits for each reporting period, and imposing a significant penalty for non-compliance on retail sellers that fall short. This proposed penalty is sufficiently large to ensure full compliance.

b. "Customer Choice" Renewable Portfolio Standard (RPS)

Submitted by: Independent Energy Producers Association (IEP)

IEP's RPS proposal is for a market-based program that does not require legislation. The program emphasizes customer choice in procuring renewable energy resources through direct bilateral contract opportunities and the buying/selling of renewable energy credits (RECs). Retail energy providers may be certified as "green" energy providers, if they meet certain standards, thereby providing customers with additional assurances that their retail provider has attained a certain level of renewables in its resource portfolio. The PUC-regulated utility distribution companies (UDC) serve as a "regulatory backstop" to ensure attainment of the RPS. The UDC enters the renewable market, if necessary, to procure renewable energy (kWhs) representing the difference between what the RPS proscribes and what the market achieves on its own. Costs borne by the UDC are passed through to all distribution customers (including direct access customers) not self-procuring renewables. The PUC provides regulatory oversight over the UDC to ensure timely and efficient compliance.

Renewable energy is that defined by existing state law. The RPS would be set to the extent practical at the level of diversity that existed as of 1993 (i.e. renewable kWh as a percentage of total annual kWhs), including a solid-fuel biomass technology band, plus preliminary BRPU winners.

c. Renewable Capacity Credit Proposal

Submitted by: Northern California Power Agency (NCPA)

The renewable resource capacity credit proposal requires all retail sellers of electricity to end-users in California to acquire and cancel renewable resource capacity credits (RRCCs), measured in 100 kilowatt increments, equal to 18 percent of the sum of their monthly peak loads during the preceding twelve months. RRCCs are created when a facility, located in California and using a renewable electric generation technology, operates at a level equaling or exceeding the average capacity factor for facilities of that type. Facility capacity is determined by the owner and registered with the California Energy Commission; it may be less than nameplate rating.

Registered capacity is the basis for both qualifying capacity factor and RRCC issuance. Renewable electric generation technologies are defined conventionally, including hydropower, wind, solar, geothermal, biomass including solid fuel and landfill gas, and hybrids not exceeding 25 % fossil input. RRCCs are issued monthly to facility owners. RRCCs are tradeable on a Capacity Credit Exchange administered by the Energy Commission, which also issues credits, establishes average capacity factors, verifies operation of facilities and enforces retailers' compliance with the standard. Failure to meet the standard subjects a retailer to a penalty equal to 1 mill/kWh of sales.

d. Single-Band Renewable Portfolio Standard (SB-RPS)

Submitted by: Southern California Edison Company and Pacific Gas & Electric Company

This version of the minimum renewables purchase requirement (“MRPR”) requires that all CPUC-jurisdictional or all statewide entities selling to end-users in California annually demonstrate that either 10% of the energy they sold to end-users in California is from renewable energy sources or that they have ensured that an equivalent amount of renewable energy has been provided to the California market through purchase of tradeable credits. (The amount of energy purchased from renewable energy sources or the number of credits purchased may of course exceed the 10% requirement.) There are no special technology bands; hydro is excluded from the definition of renewables; and the value of all renewable credits related to existing QF contracts flows back to the ratepayers. Renewable credits may be purchased at a price of 2 cents/kWh from the state agency responsible for administering the program. This ability to purchase renewable credits from the state agency effectively establishes an upper limit on the cost of the program to end-use customers

The purchase obligation is established on all sellers under the CPUC’s jurisdiction on January 1, 1998. If this obligation is not extended to all providers to end-use customers statewide through legislation by the end of the year 2000, the obligation would be eliminated. Following the year 2000 and until termination, the obligation and other parameters of the standard are to be fully reviewed every five years.

e. All Renewable Credit Proposal

Submitted by: Sacramento Municipal Utility District (SMUD)

The All Renewable Credit Proposal (ARC Proposal) strives to maintain the current level of electrical resource diversity supplying California consumers at 21% renewables. The ARC Proposal maintains this diversity by giving credit to all renewables and requiring that 21% of the electricity supplied to California consumers be from renewable resources in the future. No suppliers are exempt from this requirement. All retail sellers will need to report their power sources and their sales. If sellers do not meet the 21% renewable source requirement, they can purchase credits from other California retail sellers having surplus renewable generation. Hydroelectric resources will be eligible for credit toward meeting the 21% requirement if the resources are California utility owned, or continuously under utility or retail seller contract since 1995. In order to avoid having existing hydroelectric resources supplant other renewable resources in the future, the purchase or sale or trading of renewable credits is **not allowed** for hydroelectric resources already in place in 1995. New hydroelectric resources, including upgrades, are eligible for both meeting the 21% requirement as well as credit trading or purchases.

As an alternative to renewable credit trading or purchases, a fund might be established to procure renewable resources for those unable to do so themselves. A restriction would apply to these purchases such that purchases made to enhance renewable diversity would not be allowed for hydroelectric resources already in place in 1995.

2. Surcharge-Funded Production Credit Proposal

Submitted by: Environmental Defense Fund, Cambrian Energy Development LLC, Genesis Energy Systems, Laidlaw Gas Recovery Systems, Landfill Energy Systems, 1Los Angeles Sanitation Districts, NEO Corp., Orange County, City of Sacramento, Sonoma County, San Diego Gas & Electric, Pacific Gas and Electric, Southern California Edison, Solid Waste Association of North America

This proposal encourages the continued development of renewable projects and technologies in California, through a statewide, state-administered program funded by means of a uniform, statewide public goods surcharge collected from all end users in the State. The surcharge is intended to foster new development in renewable generation projects. The program would be available to wind, solar thermal and photovoltaic, geothermal, biogas, landfill gas, solid fuel biomass and waste-to-energy technologies. This proposal can accommodate provisions for emerging technologies. The proposal is applicable to existing projects to the extent that (1) existing projects add new capacity (applicable to additional energy resulting from such addition) or (2) existing projects replace existing generation technology with new generation technology (applicable to portion of energy resulting from replaced generation) and (3) no energy or capacity resulting from the new or replaced facilities are subject for sale under a standard offer contract.

The proposal is intended to be funded on a statewide basis. Distribution companies, including municipal utilities, would be responsible for collection of the surcharge. This proposal could, if necessary, be implemented in two stages. Stage 1: funded through the IOUs only and implemented under existing Commission authority; Stage 2: once legislation is passed would expand program to statewide implementation. Funds would be transferred to and distributed by the California Alternative Energy and Advanced Transportation Financing Authority or some other State agency.

This proposal prescribes an administratively straightforward, non-discretionary method of allocating the surcharge funds: renewable projects compete for funds on the basis of the incremental above market cents-per-kilowatt-hour level of support they require. Funds would be provided as a cents-per-kilowatt-hour production credit only for the actual energy produced. The cents-per-kilowatt-hour production credit would be set up-front, and would be fixed for a 10-year period in order to support the financing of renewable projects. The production credits would supplement the revenues renewable projects receive from marketing their power, either through sales to the Power Exchange, or sales through contracts for differences or bilateral arrangements.

New allocations of production credit awards are intended to be made each year over a five-year period beginning in 1998. Credits awarded in any year would be secure for their 10-year duration. In accordance with the direction provided by the Commission in D. 95-12-063, the program would be reviewed in the year 2000 before subsequent production credit allocation awards were made.

B. Adjunct Proposals

a. Electricity From Landfill Gas And Other Biogas; Climate Active Gas Mitigation In Utility Restructuring

Submitted by: Monterey Regional Waste Management District, City of San Diego, Sacramento County, Yolo County, International Power Technology, Royal Farms, Institute for International Management (IEM), EMCON

Electric power fueled by biogas, from landfills and other sources, already amounts to about 200MWe in California, with its potential several-fold higher. Capture and energy use of biogas substantially reduces emissions of methane to the atmosphere. Because methane's greenhouse potency is equivalent to over 20 times its weight of carbon dioxide, electricity from biogas has benefits in climate change mitigation exceeding those of other renewable energy sources. Landfill gas use, alone, could offset by 10% or more total greenhouse gas (mainly CO_2) emissions by the California electric utility industry.

Consideration and promotion of renewable electricity climate benefits is consistent with California and federal policies, and international treaties (the "Rio Convention"). Nearly all California utilities are signatories to the voluntary U.S. Climate Challenge Program, to reduce climate active gases. This proposal presents an approach to include the specific climate benefits of biogas utilization into the proposed Renewable Energy Credit (REC). The mechanism involves a subsidiary component of the REC--the Greenhouse Environmental Credit (GEC). The GEC allows technologies providing higher climate change benefits to receive expanded credit. Credit would apply specifically to electricity from landfill and other biogas sources, much or all of whose methane would otherwise escape into the atmosphere. Whenever greenhouse gas mitigation (fossil CO_2 offsets) can be obtained at sufficiently low cost (by criteria herein) it is proposed that electricity from biogas be allowed to expand independently, without affecting other renewables' uses. We propose and justify, for landfill and other biogas, a value for the GEC equivalent to an additional REC, and propose mechanisms for its implementation.

b. Emerging Renewable Technologies Commercialization Pathway

Submitted by: the California Solar Energy Industries Association (CalSEIA), the Solar Energy Industries Association (SEIA), the California Energy Commission Energy Technology Development Division (CEC/ETD), and the Natural Resources Defense Council (NRDC)

The Commission's December 20, 1995 decision recognized the need for a diversity of renewable resources and for the development of new renewables which would enhance this diversity. All of the “comprehensive” proposals presented by the Renewables Working Group (RWG) would primarily support existing generating facilities which utilize well-established renewable technologies. This is because these other proposals require all technologies to compete equally based solely on the current costs of generation. Valuable new solar and other emerging technologies will inevitably lose out in these proposals, as they are presently in the early stages of the commercialization process, and, consequently, their costs today are higher than that of the well-established wind, geothermal and biomass technologies. Indeed, this “adjunct” proposal would not be necessary if some means of accommodating higher-priced new renewable technologies were spelled out in the other proposals.

In order for these emerging renewable technologies to reach the cost levels of the well-established technologies, a pathway must be established which creates the small markets required at early stages of commercialization. Early markets will enable emerging technologies to achieve the production efficiencies and cost reductions inherent in the commercialization process. This proposal outlines a number of ways in which small, but critical, markets for new, emerging technologies could be created, and can be amended to any of the "comprehensive" proposals.

Adequate resource diversity requires that this missing commercialization pathway be provided for in whatever implementation strategy the Commission ultimately adopts.

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Chapter 3

COMMONALITIES AND DIFFERENCES AMONG STRATEGIES

This chapter of the Renewables Working Group report examines the areas of commonality and differences among the various proposals that have been submitted to the Working Group. Proposal abstracts are presented in Chapter 2, and the complete text of the proposals in Chapter 4. The analysis of commonalities and differences covers all of the implementation issues that have been identified by the Commission and the Working Group, and concentrates on those areas considered to be key to the development of a successful renewables program.

A. Renewables Program Implementation Proposals

There are a number of ways to separate the proposals into functional categories for purposes of comparing and contrasting them. This can be done in a hierarchical structure, as illustrated in Figure III.1. The first category used for separating the proposals into functional categories concerns whether or not the proposed program is based on the establishment of a minimum renewables purchase requirement (MRPR). The next category is based on the unit of measurement used by the proposed program, which can be either energy units (kWh) or capacity units (kW). The third category differentiates between proposals that do or do not include specified technology bands to promote targeted technologies. The fourth category addresses the issue of whether hydroelectric generating systems are included in the program. The final category concerns the issues of program enforcement, penalties, and cost control. This structure allows all six of the comprehensive program proposals to be differentiated with respect to their most significant functional differences. The adjunct proposals are also included in the figure.

A summary of the proposals and some of their distinguishing characteristics follows:

1. Comprehensive Program Proposals

a. Proposals With an MRPR Standard

AWEA/CBEA/GEA/STEA/UCS/CIWMB: Includes an MRPR, based on energy units, has one specified technology band for biomass, excludes hydro, employs a high, punitive penalty intended to motivate full compliance, and uses a credit price cap to control program costs.

IEP: Includes an MRPR, based on energy units, has one specified technology band for biomass, excludes hydro, and is predicated on voluntary compliance through green marketing by electricity providers, with a requirement for UDCs to purchase the necessary quantity of additional renewables to meet the MRPR standard, which will be enforced by PBR incentives.

INSERT FIGURE 3.1 HERE

NCPA: Includes an MRPR, based on capacity units, has no specified technology bands, includes hydro, and employs a penalty that applies to all kWh sold by a non-complying electric services provider intended to motivate full compliance.

SCE/PG&E: Includes an MRPR, based on energy units, has no specified technology bands, excludes hydro, provides for enforcement penalties to be set by the program administrator, and uses a credit price cap to control program costs.

SMUD: Includes an MRPR, based on energy units, has no specified technology bands, includes hydro, and does not address the issues of enforcement, penalties, or program cost.

b. Surcharge-Funded Production Credit Proposal

EDF/Cambrian/Genesis/Laidlaw/Landfill Energy Systems/LASD/NEO Corp./Orange & Sonoma Co./City of Sacramento/ SDG&E/PG&E/SCE/SWANA: Based on a surcharge funding approach, credits based on energy units, has no specified technology bands, excludes hydro, and provides for enforcement by the program administrator, with program cost set administratively.

2. Adjunct Proposals

The adjunct proposals received by the Renewables Working Group are limited-purpose proposals targeting emerging renewable energy technologies that are not yet fully competitive with conventional renewable generation, but which the proposers believe provide benefits in the forms of improved environmental quality and/or increased resource diversity. These proposed adjunct programs can be applied to any of the comprehensive program proposals submitted to the Renewables Working Group, and presented in this report.

BWG: Proposes to create special-purpose “greenhouse environmental credits” equal in value to a renewable energy credit for the purpose of promoting the growth of electricity generation from landfill gas and other biogas sources, technologies that assist in mitigating the effects of methane gas emissions.

CalSEIA/SEIA/ETDD/NRDC staff: Proposes to create small markets for emerging technologies, such as photovoltaics, that are progressing from the RD&D phase towards full market competitiveness with more established generating technologies.

B. Positions of the Proposals with Respect to Key Issues

The six full program proposals and two adjunct proposals to implement the CPUC’s renewables policy offer a wide range of options regarding the structure and design of an effective renewable energy program. Table III.1, *Features of Proposals to Implement the CPUC Renewables Policy*, presents the major issues that should be a part of any renewables program developed by the CPUC or the California State Legislature, and summarizes the

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Legend for Table: Features of Proposals to Implement the CPUC Renewables Policy

1. Program Obligation

Program Based on: A minimum renewables purchase requirement (MRPR) standard, or surcharge-funded production credits, can be denominated in either energy units (kWh) or capacity units (kW).

Basis for Initial MRPR: Most of the proposals have, as one of their objectives, the preservation (in some form) of the existing renewable energy industry in the state. This category shows the basis or objective for the setting of the proposed initial MRPRs by the various proposers, for proposals including an MRPR.

MRPR with Full Implementation: The proposed MRPR standard (for those proposals containing an MRPR standard), which in all cases is a percentage of a defined block of electricity that must be renewable. With full implementation means that, for those proposals that permit a two-phase implementation (initially by the CPUC, subsequently by the legislature), this column indicates the level of the proposed standard with the program fully enacted. Most of the proposals would adjust their proposed standard to meet their stated program goals, subject to a better understanding of current levels of renewables production in California. The SCE/PG&E proposal proposes a specific percentage for the MRPR.

MRPR with CPUC Implementation: For those proposals that provide for a two-phase implementation, beginning with enactment by the CPUC for the regulated electricity market, and following with state-wide implementation, this column indicates the level of the standard proposed for enactment during the first (CPUC only) phase of the program.

MRPR Applied to: The category(ies) of electric energy or capacity that the MRPR standard is applied to, for each entity that is required to meet the obligation.

Increase in MRPR 1998 - 2000: The MRPR proposed for the first year of the program may or may not be adjusted during the first several years of the program. In all cases, load growth leads to an increase in the quantity of renewable energy required.

Specified Technology Bands: Some of the proposals include special-qualification sub-bands within the MRPR in order to guarantee minimum levels of specific technologies or classes of technologies. Band requirements, like the overall MRPR, must be individually complied with.

2. Program Eligibility

Hydro Eligibility: All proposals define biomass, geothermal, solar electric (thermal and photovoltaic), and wind technologies as qualifying renewables, in accordance with the CPUC restructuring decision. Some proposals include hydroelectric generation in the mix of eligible generating options, others do not.

Eligibility of Non-Calif. Renewables: Proposals may or may not restrict renewable energy generated from out-of-state sources from participation in the program.

Eligibility of Bulk Utility Renewables: Utility-owned renewables, mainly geothermal and, if included, hydro, may or may not be eligible for participation in the program.

Eligibility of Existing QFs: Existing QF renewables may or may not be eligible for participation in the program.

Eligibility of UDC Dist. Renewables: Distributed renewables owned by a UDC or its affiliates may or may not be eligible for participation in the program. Distributed generation is small-scale power installed in the distribution system or on a customer's site. It can capture T&D benefits and/or serve local loads.

Eligibility of Power Gen. for On-Site Use: Renewable energy that is used by the producer for on-site applications may or may not be eligible to receive RECs or production credits. Surplus or net power sold by self-generators to others is eligible to receive credits in all of the proposed programs. The entries in this column pertain to the eligibility of renewable power that is used on-site, and not sold to a distributor or user.

Eligibility of Hybrids: Hybrid generators, which use both renewable and non-renewable energy sources, require special rules to determine qualification for RECs or production credits. Some proposals give full renewable credit to hybrids that derive more than 75% of their energy from renewables, while others give only pro-rated credit. For hybrids that derive less than 75% of their energy from renewables, some proposals give pro-rated credit, others give no credit.

3. Program Administration

Application of Program: Renewables support programs can be designed for state-wide application, or for application only to electric services providers subject to CPUC regulation.

Implementation in Phases Permitted: A renewables support program can be imposed by the CPUC only on electric services providers under its jurisdiction. Application of the program to unregulated utilities will require legislative action. Some proposals allow for a two-phase implementation of the renewables program, first by the CPUC, then by the legislature. Some of the proposals are designed for state-wide implementation only. One proposal is designed for full implementation by the CPUC, without the need for legislative action. Of the proposals that permit a two-phase implementation, one proposal calls for program cancellation if state-wide implemention is not achieved, others would maintain the program at the CPUC implementation level if legislation is not forthcoming.

Administrator (full implementation): Various state or private agencies are proposed to administer the programs. The proposed administrator listed in the table assumes full implementation for those proposals that provide for a two-phase implementation.

Funding Mechanism: A renewables support program is expected to be more costly than a restructured market lacking a renewables program. The cost of the renewables program can be rolled into the price of electricity, or it can be assessed as a line-item or surcharge to electricity customers.

Program Lifetime: The renewables program may be imposed permanently (with no sunset date), imposed for a fixed term, or imposed for a limited term subject to program review and reauthorization.

Period to Determine Compliance: Compliance with program requirements can be determined over various periods of time, with a true-up period allowed or not allowed.

Commercialization Support: Proposals may or may not include provisions for assisting emerging renewable energy technologies that have moved beyond the RD&D stage, but whose cost is not yet competitive with commercially mature renewables.

4. Renewable Credits and Markets

Renewable Credits: The various proposals contain a variety of different types of renewable energy credits, including: BECs (biomass energy credits), GECs (greenhouse environmental credits), ETCs (emerging technology credits), production credits, RCCs (renewable capacity credits), and RECs (renewable energy credits).

Contract Terms for Credits: Sales of renewables credits can be for contract terms ranging from spot market to long-term commitments. Some of the proposals specify the contract terms they foresee for credits, other proposals do not address this issue.

Credits from QFs with Existing PPAs: Many existing renewable QFs have long-term power purchase agreements (PPAs) with utilities. Assignment of credits associated with renewable energy sold under existing long-term PPAs may be to the generator or to the purchaser. Some of the proposals propose to assign credits to the buyer for the entire terms of the contracts. Others propose to assign the credits to the buyer when the energy is sold under the fixed-price (FP) schedules in the old ISO4 contracts, and to the generator when the energy is sold under SRAC rates.

Cost Cap: The cost of compliance with the renewables program requirements may or may not be capped. This category shows the proposed cap on the annual cost of program compliance, if the cost is capped. For the adjunct proposals, the category shows the cap on the cost of the adjunct program only.

Compliance Penalties: Penalties for non-compliance with the renewables program may or may not be included in individual proposals.

Use of Funds Collected: Proposals may or may not specify how to use penalty or compliance funds collected, in cases where the proposals include provisions for the collection such funds.

positions of the proposals with respect to each of these issues. For the two adjunct proposals the table shows entries only for those categories that are addressed specifically by the proposals. The table illustrates the range of approaches that have been proposed to the Renewables Working Group for dealing with the key issues that have been identified by the CPUC and the Working Group. These issues are analyzed below.

1. Program Obligation Issues

a. Basis for the Obligation

The CPUC restructuring decision recommends the establishment of a minimum renewables purchase requirement (MRPR) "to meet our resource diversity goals" (p. 150, D95-12-063 as modified by D.96-01-009). The Decision further calls for the establishment of an effective enforcement mechanism in order to ensure compliance with the program. Each of the six comprehensive program proposals offers a distinct approach to creating and enforcing a renewables program in order to fulfill the CPUC's policy objectives for renewables. Five of the six proposals present strategies to implement the MRPR mechanism incorporated in the CPUC restructuring decision. The EDF et al. proposal employs an alternative approach to achieve the CPUC's policy objectives, in which a program for new renewables would be funded by a surcharge on electricity bills, with surcharge funds distributed to new renewable energy projects as production credits on the basis of a competitive bidding program. All of the MRPR-based proposals include the use of tradable renewable energy credits (RECs) to facilitate compliance and spread the costs of the program equitably across the state. Programs based on the MRPR mechanism aim to achieve a predictable quantity of renewable energy production, relying on market competition to minimize program cost. The surcharge-funded production credit approach ensures a predictable program cost, with competition for surcharge funds used to maximize the quantity of renewables generated.

All of the MRPR proposals place compliance obligations on electric services providers. The IEP proposal imposes the obligations on the Utility Distribution Companies (UDCs) only, while the other MRPR proposals impose the obligations on all providers. Two different approaches are proposed for determining compliance obligations during each defined compliance period. Several of the proposals require obligated parties to acquire a specified quantity of RECs during each compliance period that is a percentage of their sales for that period. Since exact sales quantity during a compliance period cannot be determined in advance, these proposals provide for a true-up period following each compliance period. The NCPA proposal provides for compliance obligations to be determined on a retrospective basis, based on the obligated entities' average sales volumes during the previous twelve month period. This approach facilitates REC planning on the part of obligated parties, as they know at the beginning of each compliance period what their REC obligation will be for that period.

Each of the proposals to the Renewables Working Group for the implementation of the CPUC's renewables policy utilizes one or both of two primary tools to adjust the amount of renewable energy production associated with their proposed program:

1. A standard (the MRPR) specifying the minimum amount of renewable energy that must be produced.

2. A program cost allocation or cost cap that determines the (maximum) amount that will be spent on the support of renewable energy production within the program.

The CPUC's decision on restructuring recommends the use of an MRPR standard to achieve its objectives for renewable energy. The decision leaves open the issue of whether to impose a cost cap on the program. The IEP proposal relies entirely on the use of an MRPR standard for meeting the Commission's objectives, while the EDF et al. proposal relies entirely on the use of an administratively-determined program cost allocation. Proposals that employ both an MRPR standard and a cost cap become blends of the two approaches, with outcomes in terms of renewable energy production that can be manipulated by adjustments of either variable. If the cost cap is set at a level that is lower than the marginal price of RECs needed to fulfill a mandated MRPR, then it is unlikely that the MRPR program standard will be achieved. The challenge for the Commission and the Legislature is to balance program cost and the level of renewable energy production desired.

All of the comprehensive renewables policy implementation proposals included in this report except for the NCPA proposal are based on creating obligations for the purchase of renewable *energy*, as measured in kilowatt-hours of electricity delivered to California users. In any given period of time, the MRPR percent of defined energy must be generated from renewable generating sources, or in the case of the EDF et al. proposal, renewable energy production credits are distributed to renewable energy generators based on their energy production. Denominating a program with energy units ensures that the amount of electricity produced from renewable sources, rather than the amount of renewable generating capacity in service, is the objective of the program. This is based on a belief by proposers that renewables make their greatest contribution by their operation, not just their availability on-line. It is also straightforward to monitor a program based on energy units, since electric energy routinely is metered for purposes of sales and transfers through the grid.

The NCPA proposal is based on the creation of an obligation for an MRPR percentage of generating *capacity* from renewable sources, as measured in kilowatts. The proposal includes a requirement that suppliers of qualifying renewable capacity maintain a minimum level of energy generation that is commensurate with the generating technology in question. The NCPA proposal has the advantage that the obligation for any given period of time is based on the average monthly capacity used in the state for the previous year, and thus is determinable before each compliance period begins. Entities that are obligated to amass capacity credits know before hand how many credits they must acquire, and no true-up period is required.

The capacity-credit approach is designed to minimize the uncertainty associated with annual variations in the availability of intermittent renewable generating sources (solar, wind, and especially hydro). Intermittent generators are required to bid their capacity at a level that allows qualification with regard to required energy production in poor resource years, or face derating due to failure to perform.

The requirement in the NCPA proposal that a renewable generating source provide a minimum amount of energy on an annual basis in order to qualify as having provided its certified capacity to the system in effect minimizes the difference between an energy-based MRPR and the proposed capacity-based MRPR. For example, if the administering agency determines that a given renewable technology must operate at a load factor of 80 percent in order to qualify as having met its capacity provision obligation, then bidding a generating unit using this technology at the level of 10 MW of capacity credits is equivalent to bidding a commitment of 70,000 MWh of energy to be produced over the period of a year (10 MW x 8760 h/y x 0.8). A capacity credit program that lacks this minimum production requirement would not ensure the level of renewable energy production that the NCPA proposal, or the energy-based proposals, do.

Some participants argue that a weakness of the capacity credit approach tied to a minimum production level set differently for each renewable energy technology is that the resulting values of the credits, on a per kWh basis, would vary greatly. For example, if biomass generators were required to produce at a level of 80 percent capacity factor, and wind generators were required to produce at a level of 25 percent capacity factor, then if a capacity credit were valued at $100 per MW by the market, the biomass generator would receive a capacity value of 1.4 ¢ for each kWh produced subject to capacity credit qualification, while the wind generator would receive a value of 4.5 ¢/kWh. In other words, they argue that compared to a system based on energy credits, the capacity credit approach proposed by NCPA favors renewable generating technologies that operate at inherently lower capacity factors, and thus would secure for the market fewer kWhs of renewable energy per dollar cost of the program.

NCPA believes that the relevant issue for the state's renewable program is not the arithmetic of renewable credits, but the stream of income represented by the combination of energy sales and credit sales. The high capacity-factor renewables have more energy to sell, and thus earn more annual revenue from such sales. They also have a greater annual output of energy over which to amortize their capital costs. They will receive a lower per kWh value for their capacity credits, but the significant issue is whether the total stream of income is sufficient to induce continued operation of existing facilities, and appropriate, prudent new investment. The capacity credit approach helps to put low capacity-factor technologies in a position to compete in the market.

b. MRPRs and Program Goals

All of the proposals that are based on the MRPR approach set the initial level of the state-wide standard at a level that is based to some degree on the average state-wide level of renewable energy generation that existed at the time when the initial electric utility restructuring decision was made by the CPUC (April, 1994). Two of the proposals, IEP and NCPA, would set the initial MRPR at a level intended to obligate the amount of renewables that would have been achieved at the expected time of enactment of the overall restructuring program (1998) based on production that they assume would have occurred had the BRPU process been carried through to completion as originally envisioned. The SMUD proposal sets the initial level at the level of renewable energy produced in the state in 1994, while AWEA et al. sets the level at 90% of the level of renewable energy produced in the state in 1993, with the ten percent reduction adopted in an effort to ensure competition among renewables. The SCE/PG&E proposal attempts to achieve approximately the level of renewables production that the state experienced during the first half of the 1990s. Most of the MRPR proposals provide an estimate of the MRPR level that would achieve their program objectives, but state that the actual standard adopted should be based on achieving the intended goal, rather than on the actual number offered in the proposal. The exception is the SCE/PG&E proposal, which proposes to adopt the level of ten percent as the numerical standard. It would be necessary to establish a reliable data set of renewable energy use in California during the early 1990s in order to adjust the initial MRPRs to meet stated program objectives. The Renewables Working Group was unable to produce a verifiable data base that all of the participants could endorse. This is an appropriate area for future Commission inquiry.

While all of the proposals attempt to maintain state-wide levels of renewables production at levels consistent with those of the early 1990s, it is important to note that applying the proposed MRPRs uniformly to all providers, or to all regulated providers, imposes very different implications for individual providers. San Diego Gas and Electric, for example, would have to increase it renewables purchases, either directly or through the acquisition of tradable RECs, at least ten-fold to comply with the proposed MRPR standards. Only the IEP proposal provides for a transition strategy, in which initial MRPRs for each of the UDCs, which are the sole obligates in this program, are set consistent with current levels of renewables in their individual service territories.

Most of the proposals anticipate maintaining the level of the initial MRPR at a constant value for the first three years of the program, pending an expected review of the renewables program at that time. In this case the total requirement for renewables would change in proportion to changes in total energy consumption over the period (or more exactly, changes in those categories of energy consumption to which the MRPR is applied), but the renewable percentage would remain fixed. The exception to this is the AWEA et al. proposal, which includes a provision to increase the MRPR by 0.2 percent per year over the first three years of the program. It is important to note that the AWEA et al. proposal is the only one that purposely sets the initial MRPR at a level that is below the amount of renewables produced in the state in 1993 in order to ensure competition, so that even after three years of an increasing MRPR (at 0.2%/yr), the state-wide level of the renewables program obligation will remain below the pre-restructuring level.

c. Generation Technologies Included in the Programs

California Public Utilities Code Section 701.1(a) lists as renewable generation technologies biomass (solid fuel and biogas), geothermal, solar (thermal electric and photovoltaic), and wind. Although unquestionably renewable, hydroelectric generation is not included explicitly in the list. The inclusion of new or existing hydro generation in a renewables support program is a matter of contention among the parties to the Renewables Working Group. Two of the six comprehensive program proposals, NCPA and SMUD, include hydro among the eligible technologies, while the other four comprehensive program proposals exclude hydro generation as an eligible technology for the program.

Some of the participants in the Working Group have suggested that the inclusion of hydroelectric generation in a renewables-support program presents both philosophical and practical issues. Other participants who advocate the inclusion of hydro observe that these issues are not unique to hydroelectric generation. The major philosophical issue regards the commercial and competitive status of hydroelectric generating technology. Hydro technology is fully mature and competitive with other forms of electricity generation. There is a question as to whether hydro should be given the same incentives that will be extended to the other renewables in a renewables support program. This factor is recognized by the SMUD proposal, which includes hydro as a renewable generating option for purposes of meeting the MRPR obligation, but prohibits the trading of credits associated with existing hydro generators (i.e. those commissioned before December 20, 1995). All other renewable energy credits are tradable in the SMUD program. Hydro proponents observe that biomass and geothermal technologies are also technically mature. Furthermore, operational constraints placed on hydro facilities to enhance environmental values affect their competitiveness in ways that parallel the uncertainties associated with fuel availability and price volatility for biomass and geothermal energy systems.

Some of the practical problems associated with including hydroelectric generation in a renewables support program include:

- Many hydro generators are multipurpose facilities, providing water supply, flood control, and recreational amenities in addition to power generation. Including systems of this kind in the renewables program risks subsidizing these non-energy functions. Similar considerations apply to biomass facilities, which provide ancillary waste disposal services.

- If out-of-state hydro generators are deemed eligible for the program, there is a risk that Northwest hydro sources could squeeze non-hydro renewables out of the market. To address this concern the NCPA proposal excludes out-of-state generating facilities from participation in the program, while the SMUD proposal prohibits the trading of credits associated with existing hydro facilities.

- Year-to-year fluctuations in hydro availability, which tend to be more extreme than fluctuations in other renewable energy sources, will make the timely acquisition of RECs more difficult for entities required to meet MRPR-based standards if the standard is based on energy production rather than operational capacity.

d. Competition and Diversity of Renewable Generating Sources

Renewable energy generating resources are a disparate collection of technologies that each have their own combination of characteristics and needs in order to be able to contribute to the state's electric system. For example, some renewables, such as solar electric and wind, are dominated by high capital cost, no fuel cost, and low operating cost, while others, such as biomass and geothermal, have a more conventional combination of capital and operating costs. Some of the renewables can be operated in a full or partial load-following mode, while others, notably solar electric and wind, provide intermittent power whose output profile is uncontrollable and not synchronizable to consumer demand. In addition, while all renewables may provide environmental, economic, and diversity benefits to California, the package of costs and benefits associated with each technology varies considerably.

There is an open question among members of the Working Group as to whether different renewables can compete successfully with each other, or whether head-to-head competition would eliminate some of the existing or emerging renewable generating sources from the system. There is also disagreement as to whether competition among the different renewables should be encouraged or discouraged from a public policy perspective. The CPUC restructuring decision asks whether it might be appropriate to impose individual technology bands in order to ensure its diversity goals for renewables.

Two of the six comprehensive program proposals, AWEA et al. and IEP, include a provision for a special band within the overall program for the support of one specific renewable technology: solid-fuel biomass. In these proposals, entities that are obligated to acquire a given quantity of renewable energy credits will be further obligated to ensure that a defined minimum fraction of the total REC obligation is contributed by biomass generating sources. The rationale contained in these proposals for a special biomass band is that biomass technologies provide an especially valuable package of environmental benefits including waste disposal services that are unique among the renewables, and biomass has difficulty competing with other renewables that inherently have much lower operating costs. Thus the AWEA et al., and IEP proposals consider it to be a reasonable additional program cost to preserve a minimum level of biomass power generation in the state through the creation of a specified technology band for biomass.

The two adjunct proposals, BWG and CalSEIA et al., each propose an additional mechanism to be included in the renewables support program to support selected technologies. The BWG proposes a mechanism that would be geared to the mitigation of one specific environmental insult, the emission of greenhouse gases associated with the treatment and disposal of solid wastes. BWG's rationale for their proposal is that biogas power generation provides an environmental service not provided by other renewable generating sources (the additional mitigation of greenhouse gas emissions through methane emission reductions), and, in the proposers' view, it is a reasonable deal for electricity customers to pay extra to receive this particular environmental service.

The BWG proposal does not use the conventional band mechanism to promote biogas production because, it argues, banding is most effective in preserving a level of production already achieved, and in the case of the development of the state's biogas generating resources, there is a potential to increase the installed capacity several fold. Instead, the proposal creates a new category of credits called "greenhouse environmental credits" (GEC). Each kWh of electricity that is produced from biogas produces one associated REC, and one associated GEC. Each GEC has a value equal to that of a REC, providing a significant additional incentive to the production of electricity from biogas. In order to avoid out-competing other renewable energy sources with the increased credit allocation to biogas generators, it is proposed that increases in the installed capacity of biogas generators should be accompanied by a commensurate increase in the MRPR. The intent is to leave the requirement for non-biogas renewables unaffected by the level of biogas-generated power employed in the state.

The CalSEIA et al. proposal proposes a special band or surcharge that would be used to promote the commercialization of emerging renewable generating technologies that have moved beyond the R&D stage of development, but have not yet reached the point of competitiveness with the lowest-cost renewables in the market. A variety of solar technologies, such as photovoltaics and dish-Stirling engines, and other renewable technologies fit this category. CalSEIA et al. propose that temporary support of such technologies at a higher level than the expected value of the credits associated with "conventional" renewables will help these emerging technologies to move down the technology commercialization curve and become competitive with conventional renewables and other generating sources. The special band or surcharge for emerging technologies proposed by CalSEIA et al. could be added onto any of the comprehensive program proposals for the implementation of the CPUC's renewables policy included in this report.

The six comprehensive program proposals do not include provisions for the commercialization of emerging technologies, arguing that the CPUC's renewables policy is intended to be a support program for competitive renewables sources, and not a mechanism for the support of technology commercialization. On the other hand, no other mechanism currently exists to provide the type of commercialization support that is the objective of the CalSEIA et al. adjunct proposal. Since the commercialization band probably is not going to engender the level of competition that is expected within the MRPRs of the full program proposals, commercialization alternatively might be pursued via a surcharge-funded program that runs as an adjunct to whatever renewables program is adopted. One of the options proposed by CalSEIA et al., a commercialization surcharge program, would be compatible with any of the comprehensive program proposals, whether the basic program is based on an MRPR or surcharge-funded production credits. If it is added on to a surcharge -funded program, it becomes an administrative decision to determine what proportion of the total funds collected would be allocated to emerging technologies. For roof-top PV, CalSEIA et al. has also proposed that surcharge funds could be administered as part of either the R&D or energy efficiency programs.

2. Program Eligibility Issues

a. Out-of-State Renewables

Most of the comprehensive program proposals for the implementation of the CPUC's renewables policy place no restrictions on the participation in the program of renewable generating sources that are located outside of California. Most of the proposers believe that, while restricting the program to in-state renewable generating sources would be economically desirable for California, placing any such restrictions in the program would be contrary to the Commerce Clause of the U.S. Constitution, which prohibits restrictions on interstate trade. The exceptions are the AWEA et al. and NCPA proposals. The NCPA proposal takes the position that restricting participation in the program to in-state renewable generating sources would be both legal and desirable. The basis for this position is that renewable generating facilities provide unique local environmental and public health benefits that justify restricting program eligibility to local generating facilities.

The AWEA et al. proposal adopts a narrower version of this rationale. It places no restrictions on out-of-state generators in the general RECs market, but does restrict participation in the biomass BEC market to in-state biomass generators. The proposal recognizes Commerce Clause considerations, but believes that in the case of the biomass set-aside there may be a sufficient in-state interest to allow the restriction to be applied. AWEA's rationale for restricting participation in the biomass band to in-state sources is that the reason for establishing this special band in the first place is to secure for the state the waste disposal benefits of biomass power generation, such as reductions in open agricultural burning, reductions in landfilling requirements, and reductions in forest fire risks via the removal of excess fuel from the forest. These benefits accrue to California if biomass facilities use only biomass originating in California. The Renewables Working Group is unable to provide legal guidance to the CPUC on Commerce Clause issues.

b. UDC-Owned Renewables

One renewable energy application that presents a special set of issues from the regulatory perspective is utility distribution company (UDC) owned distributed generation. Distributed generation takes the form of smaller disbursed generating facilities located at a customer, utility or other location. Distributed renewables can include photovoltaic, wind and biomass technologies. Distributed renewable generation could be owned by Utility Distribution Companies, customers or third parties, such as green direct-access providers. At a customer's premises, distributed renewables could include self-generation, third party on-site generation, or utility generation connected on either side of the meter.

Some utilities and others have proposed that utility-owned distributed generation be considered T&D plant and therefore exempt from the unbundling of generation from T&D1. This would permit UDCs to use distributed renewables to substitute for T&D expansion, in effect "leapfrogging" T&D congestion by moving their generating resources closer to customers. The potential of the UDC to cross-subsidize their distributed generation with savings on the T&D side is also an issue in restructuring, as is the locational market power concern related to the UDC's unique status among potential distributed generators as the owner of the distribution system.

Another potential issue is the power exchange purchase requirement of UDCs. Under restructuring, utilities are required to obtain energy through the power exchange. However, distributed generation may be unsuited to bidding into a power exchange due to transaction costs, non-dispatchability, line losses, unfeasibility of wheeling power from distribution to transmission, etc.

The AWEA et al., CalSEIA et al., and IEP proposals state that UDC-owned distributed renewables should not qualify for RECs until these issues are resolved. The AWEA et al. and CalSEIA et al. proposals would accelerate the commercialization of distributed renewables through the pass-through of T&D benefits to customers and third parties, and through the use of energy efficiency and RD&D moneys. The NCPA proposal would also make UDC-owned distributed renewables eligible for RECs. The EDF et al., and SCE/PG&E proposals state that UDC-owned distributed renewables may be eligible for subsidy by surcharge-funded production credits or RECs once CTC recovery is completed and the Commission has resolved the functional unbundling and other issues in restructuring. The SMUD and Biogas proposals do not address the question of distributed renewables owned by UDCs.

c. Existing Renewables

The five MRPR-based proposals make existing utility-owned and QF renewable power generators eligible to participate, on a competitive basis, in a renewable credits program. The

1 SDG&E, EPRI, and four utilities outside California are funding a study of legal and regulatory issues connected with this issue. All three California IOUs have conducted ratepayer-funded RD&D into integrating distributed generation into their T&D systems. The SCE/PG&E proposal suggests "RECs being awarded to distributed utility-owned renewable power" (see answer to question a.9).

only exception to this rule is the SMUD proposal, which includes hydro in the program, but prohibits the trading of credits associated with existing hydro generating sources. The authors impose this restriction in order to limit the market power of existing hydro generating sources within the overall renewables market. The existing hydro generators are counted towards the renewables obligation of the UDC that distributes their power, but their credits are not transferable.

The EDF et al. production credit proposal excludes existing and future utility-owned renewables from participation in the surcharge program until CTC issues have been resolved and CTC amounts fully collected. Non-utility owned renewable generating sources would only be eligible to participate if their in-service date is post December 20, 1995 (the date of the CPUC restructuring decision), or if there is substantial redevelopment of a facility after that date. As such, under the EDF et al. proposal, existing QFs would not be eligible to participate in the surcharge-funded production credit program regardless of whether they continued to sell under existing power purchase contracts. As currently drafted, this program is designed to encourage the development primarily of new renewables projects.

d. Renewables Generation for On-Site, Own Use

Some of the renewable energy generated in California is used on-site by the generator[2] , rather than being sold to the utility companies for distribution and sale. Renewable self-generation occurs in two major situations: in non-grid connected applications for which the cost of grid connection would be more expensive than the cost of installing and operating an on-site renewable generating system, and in grid-connected applications for which the generator supplies his own energy requirements from a combination of the renewable generator and the grid, and supplies net or surplus renewable power to the grid. Renewable self-generation can vary in scale from a 200 W solar home system to a 50 MW biomass cogeneration system associated with a pulp and paper mill.

All of the comprehensive renewables program proposals would award RECs (or RCCs or production credits) to the quantities of surplus renewable energy generation that grid-connected self generators provide through a utility meter (eventually) to a customer. Two of the proposals, IEP and SMUD, would also award RECs for renewably generated power that is used on-site by the generator, while the other four proposals would prohibit such power from qualifying for RECs. Those four proposers are concerned that it may be impractical to award credits to self-generation because power consumed on-site is not officially tracked or sold through a regulated meter. Hence, the kWhs of self-generation cannot be verified. Some members of the working group believe that inclusion of self-generation in the renewables program might encourage electricity users to avoid public purpose charges and the CTC.

2 For purposes of this discussion, power that is used within the renewable generating facility, commonly referred to as parasitic power, is not considered to be self-generation.

e. Hybrid Generators

Renewable generating technologies that incorporate heat engines in their systems are capable of operating with both renewable and non-renewable energy sources, in a hybrid generating mode. Renewables in this category include biomass, geothermal, and solar thermal electric generation. There are technical and efficiency reasons as well as economic reasons why generating facilities using these technologies choose to hybridize routinely with natural gas as an energy source, on both a spot and continuous basis. PURPA allows a renewable generating facility to obtain up to 25 percent of its energy input from non-renewable sources and maintain its qualifying status as renewable.

For purposes of qualifying for renewable energy credits, several approaches are possible for the treatment of hybrids, all of which are represented in the six comprehensive program proposals. The two basic approaches are: (a) pro rate the renewable portion of the generator's output for purposes of REC qualification, and (b) set a minimum renewable qualification for the generator and give full REC credit for complying facilities. Three of the proposals (SCE/PG&E, SMUD, and EDF et al.) would assign pro-rated credits for hybrids using any combination of renewable and non-renewable energy. The AWEA et al., IEP, NCPA, and CalSEIA proposals establish a 75 percent renewable qualification minimum, and award full renewable credits for generators that meet the minimum renewable rule. The IEP and NCPA proposals would establish a 75 percent minimum renewable qualification would assign no RECs to hybrids that do not meet the minimum qualification rule, while the AWEA et al. proposal allows pro-rated credits for such facilities.

3. Program Administration Issues

a. Program Administration

The Decision on electric utility restructuring expressed a preference for state-wide implementation of its renewable energy policy, which can be accomplished only through legislative enactment of the program. Due to jurisdictional considerations, CPUC programs only apply to the investor-owned, regulated electric utility sector. Most of the proposed comprehensive renewables programs are designated for state-wide application, although some of them allow for a two-phased implementation, beginning with the regulated electric utility sector, and extending in the second phase to the entire electric utility industry in the state via legislative enactment. The AWEA et al. proposal provides for a two-phase implementation approach would continue the program at the CPUC level regardless of the status of state-wide legislative implementation. The SCE/PG&E and EDF et al. proposals would allow for initial CPUC implementation, but recommend canceling the program if timely legislative enactment were not achieved. The NCPA and SMUD proposals are designed for implementation at the state level only. The IEP proposal, in an effort to facilitate the implementation of the CPUC's renewables policy, is designed around enactment at the CPUC level only. State-wide application of the program would be welcomed by the IEP, but the program is designed to achieve its full program goals with CPUC implementation.

Two of the MRPR proposals, AWEA et al. and SCE/PG&E, provide for a two-phase implementation of the renewables program, but they take a different approach to how to phase-in the program. The AWEA et al. proposal would apply higher standards during initial CPUC enactment of the program, in order to achieve full program objectives in terms of state-wide renewables use within the limited context of the regulated electricity sector. Upon state-wide enactment, the standards would be adjusted to achieve the same renewables production level over the extended participant base. The SCE/PG&E proposal would set the MRPR standard at ten percent during initial enactment of the program by the CPUC, the same level that would be applied state-wide when the program is so extended.

The CPUC's electric utility restructuring program is scheduled to be implemented at the beginning of 1998, with a review of the renewable program expected to take place after the third year of the program's operation. Most of the proposals contain no sunset date, in order to create the long-term commitment that is necessary to attract investments in new renewables generating capacity. Several of the proposals point out that the programs will automatically sunset themselves if and when market conditions make renewables fully competitive with non-renewable electric generating sources. These proposals do not indicate whether they believe subsidies should continue indefinitely should renewables not be able to compete head-to-head with other generating sources in the future. Two of the proposals, SCE/PG&E and EDF et al., suggest that during the program review following the year 2000 a specific determination be made regarding the continuation of the renewables program. The EDF et al. program proposes to award production credits through a series of five annual auctions. Successful bidders will be awarded contracts for production credits with ten-year terms, beginning with the in-service date of the auction winners.

The comprehensive program proposals present several different alternatives for the administration of a renewables program. Four of the proposals provide for the administration of the program to be carried out by an appropriate state agency, with the CEC named specifically in the NCPA proposal. The AWEA et al. proposal allows for either a state or private agency to act as administrator. The SMUD proposal calls for administration of the program to be conducted by means of the wholesale power exchange and independent system operator, which will be created as new institutions during the first phase of the implementation of the CPUC's overall restructuring program. The IEP proposal takes a different approach, assigning administrative duties to the UDCs (utility distribution companies) that will be created as part of the restructuring process. The IEP proposal does depend on state agencies to provide certification standards and services to the renewables program. The EDF et al. proposal suggests assigning administrative duties to the California Alternative Energy and Advanced Transportation Financing Authority, but does not preclude the use of other appropriate state agencies to provide administrative services for the program.

b. Compliance and Enforcement

The CPUC restructuring decision calls for the enactment of a renewables program that is supported by effective compliance and enforcement provisions. Each of the comprehensive proposals takes a different approach to addressing this aspect of the program. The AWEA et al. proposal would impose a high, punitive penalty (6 ¢/kWh) on electricity providers that fail to acquire a sufficient quantity of RECs to meet their program obligation, with the intention of ensuring full compliance at all times. The penalty is applied to the shortfall in a provider's renewables obligation. Full compliance is further assured by setting the initial MRPR at a level that can be met with only 90 percent of the renewables production actually produced during 1993. The proposal provides cost control by including a cost cap for the RECs (2.75 ¢/kWh) and BECs (3.75 ¢/kWh). If the program administrator sells credits at the cap price, the funds collected will be used to conduct a secondary auction, purchasing credits from the market at whatever price is offered subject to the availability of funds.

The IEP proposal emphasizes voluntary compliance by non-UDC providers through direct-access green marketing, and requires the UDCs to acquire any additional renewable energy credits necessary to meet the state-wide MRPR standard, with their costs billed as a line-item charge to all UDC customers, including direct-access customers. The line-item charge will be applied in the same manner as public purpose charges or the CTC. Direct-access customers of certified "green-energy" providers will not be assessed the line-item charge. "Green-energy" certification will require providers to at least meet the MRPR standard in their portfolio of resource supply. The UDCs are responsible for administering the program, and demonstrating that the MRPR is met. Enforcement of this responsibility will be carried out as one aspect of the PBR regulatory process to which the UDCs will be subject in the restructured electricity market. No penalties are specified, and the program does not have a cost cap.

The NCPA proposal gives the CEC responsibility for administering and enforcing the renewables program. Electricity providers subject to the program are required to surrender the required number of RCCs, or face a penalty payment of 1 mill per kWh assessed to their entire volume of power sales. The penalty acts as a cost cap for the program, and all penalty funds collected would be devoted to renewables R&D. A drawback to a penalty that is assessed to a provider's entire sales volume is that it does not provide an incentive to achieve partial compliance in cases where a provider cannot achieve full compliance at a cost that is below the cap. In such cases a provider might choose to pay the penalty in lieu of participation in the program, which could suppress the value of RCCs across the board.

The SCE/PG&E proposal includes provisions for a 2 ¢/kWh price ceiling to be applied to the shortfall of RECs that a provider is obligated to acquire, as well as possible penalties for fraudulent behavior. The ceiling price is intended by the proposers to be a fee, not a penalty, and to act as a cost cap for the renewables program. Funds collected from ceiling payments made in lieu of the acquisition of RECs could be used to reduce the CTC, or to promote the development of new renewables.

The SMUD proposal does not address the issue of penalties and enforcement in their proposal.

The EDF et al. proposal is based on a surcharge-funded program rather than the establishment of an MRPR, so enforcement requirements for the program are different than for the MRPR-based proposals. The program is based on the use of an administratively-determined cost to be used to fund renewable technologies. The proposers do not recommend a specific overall funding level, but do use as an example a program funding level of $125 million, assuming the program is enacted on a state-wide basis. Compliance incentives or penalties are not expected to be necessary for this type of program. The program funds would be administered by a state agency.

The CalSEIA et al. proposal does not specifically address penalties for non-compliance, but it does propose a cost cap on the price of credits for the emerging technologies band. The cap would not be a fixed price, but rather would be set at some specified multiplier above general REC trading prices. If market price reached the cap, it would trigger the program administrator to sell credits at the cap price and use the proceeds to fund increased renewables generation.

c. Renewable Credits and Credit Markets

The CPUC's restructuring decision proposes a renewables program based on an MRPR that is intended to be applied state-wide to all electricity sales to end users. In order to facilitate compliance and minimize program cost, the decision envisions the creation of a market for the trading of renewable energy credits, allowing electricity providers in the state that are deficient in renewable generating resources to fulfill their obligation by purchasing credits that are available from renewable energy used anywhere in the state. Renewable energy generators benefit by having two commodities to sell, renewable energy and its associated RECs. In addition, the purchasers of renewable energy may benefit from the resale of RECs to retail sellers that require additional credits to meet their MRPR requirement. The value of the RECs is intended to provide the above-market increment that renewables generators need in order to be able to compete in the restructured market. The value of the RECs will be controlled by market competition, assuming that a competitive market is engendered by the program. The five MRPR-based proposals offer several alternatives for the structuring of a competitive REC market.

Most of the proposals are non-specific with respect to the structure or mechanism of the market that would be created for the trading of RECs. The proposals would allow a variety of transfer mechanisms to develop, including bilateral contracts, packaged energy and REC sales contracts, long-term contracts, and spot sales. In most proposals, providers of energy to California end users are obligated to acquire a minimum quantity of RECs sufficient to satisfy their MRPR obligation. These RECs are to be surrendered to the designated administrator at the end of each compliance period.

The SMUD proposal offers a different approach to the operation of a REC market, taking advantage of the creation of the wholesale power exchange and independent system operator (ISO) as part of the restructuring process. The power exchange will purchase all power to be grid-distributed in the state as restructuring is implemented, and will be responsible for the acquisition of power at lowest cost. The ISO will be responsible for ensuring that system integrity and reliability standards are maintained. SMUD's proposal suggests that it would be a natural extension to have the exchange also be responsible for acquiring the necessary quantity of RECs, with the cost distributed proportionally to electric service providers as they take power from the exchange for distribution to California end users. The exchange would be given the same latitude to balance firm and spot REC purchases as it has for energy purchases. SMUD contends that this system would avoid the market power problem that could arise in a market operating with a limited number of purchasers of RECs.

d. RECs from Energy Sold Under Existing PPAs

All of the MRPR proposals agree that the generator of a REC may sell that REC, just as he sells his output of kWhs. In situations where renewable energy is being sold under long-term power-purchase agreements (PPA) that pre-date market restructuring, however, the assignment of RECs is far from clear. Since the RECs did not exist at the time the PPAs were formulated, there is no specification regarding REC transfer in these contracts. This is an issue of considerable significance for the implementation of an MRPR program, as much of the renewable generating capacity that will be available during the enactment of the program will be bound by existing, long-term PPAs, some of which extend more than twenty years beyond the planned restructuring implementation date.

The proposals (AWEA et al., IEP, SCE et al., SMUD) that offer a directed solution to the issue of assignment of RECs for renewable energy sold under pre-restructuring PPAs agree that in cases where renewable energy is being sold under the fixed-price schedules included in standard-offer PPAs (specifically Interim Standard Offer #4 PPAs with the appropriate selections made), the RECs associated with this energy would be considered to be packaged with the energy, and the property of the purchaser (i.e., the utility).

There is considerable disagreement, however, regarding the assignment of RECs associated with energy that is being sold under pre-restructuring long-term PPAs, when energy is sold at the short-run avoided cost (SRAC) rate, and capacity is sold at long-term levelized contract rates. The AWEA et al. and IEP proposals assign all RECs associated with energy sold at SRAC to the generator. This means that the generator would receive the benefits of the newly-created RECs, which were not anticipated during the negotiation of the original PPAs.

The SCE/PG&E, and SMUD proposals assign all RECs sold under pre-restructuring long-term PPAs to the purchaser on behalf of ratepayers. The eventual disposition of RECs associated with renewable energy sold under pre-restructuring PPAs will have important implications on any negotiations that may take place having to do with the restructuring or buyouts of existing PPAs.

One of the reasons that a renewables support program is being considered by the CPUC is an expectation that renewable power generators will have trouble competing in a competitive electricity market. The purpose of the creation of a RECs market and REC procurement requirements for electric services providers is to provide the necessary increment of value (above market) that is necessary to allow renewables generators to produce renewable power in the restructured market. The economic viability of renewable generators operating under existing PPAs, with energy sold under SRAC and long-term capacity sales, in the restructured market is questionable. Assuming that SRAC represents full market value in the restructured market, as it is intended to do, then facilities receiving SRAC plus capacity payments will be above market by the value of the capacity payments. How the value of capacity payments will compare with the value of the newly created RECs is difficult to predict.

The NCPA proposal addresses the issue of the assignment of RECs (in their case, RCCs) associated with renewable power sold under pre-restructuring PPAs by directing the parties to the contracts to negotiate the disposition of the soon-to-be created RECs. The existing PPAs are legally binding contracts, and any changes to them will have to meet the requirements of contract law. The CPUC has posed as an important implementation issue the question of whether restructuring efforts will or will not produce incentives to re-negotiate existing contracts. The issue of assignment of RECs under existing PPAs is one area where this issue must be considered carefully.

e. Competition and Marketing of RECs

The overall restructuring of the electricity market is predicated on the goal of making the market more competitive. The CPUC's renewables policy, too, is intended to be subject to the rigors of market competition. Such competition can take a variety of forms. The broadest possible competition, which should lead to the lowest possible program cost (or maximum renewables production under the production credit program), would allow all renewables to compete together, both among different technologies, and between existing and new generating installations. Competition among different renewables technologies has been discussed previously under heading A.1.d. *Maintaining Renewables Diversity*.

The restructuring decision's policy goals for renewables include both maintaining the resource diversity for existing resources, and encouraging the development of new renewables. The development of new renewable generating sources may be difficult unless long-term contracts for sales of renewable energy and RECs can be obtained by developers hoping to secure funding for their projects. Most of the MRPR proposals leave the development of REC contracts to the market. No special provisions are included to facilitate the development of contracts tailored to the specific needs of new generating sources. The EDF et al. production credit proposal, in contrast, is for a program that would be tailored to the development of new renewables, offering winning bidders ten-year commitments for the payment of production credits, and barring existing facilities from participating in the bidding program. IEP suggests enacting incentives to facilitate the development of new renewable generating sources. These include developing a Renewable Trademark easily recognized by consumers, offering a CTC credit option in which direct access customers entering into contracts with renewable QFs would be eligible for a credit of all or a portion of the CTC, and implementing a renewable energy purchase requirement for state facilities.

The CPUC restructuring decision relies on the creation of an enforceable standard to achieve its policy goals for renewables. The decision does not address the issue of green marketing directly. The Renewables Working Group, however, has asked each of the proposers to address the issue of how green marketing might fit into the context of their proposals. The IEP proposal is designed around the concept of using green power marketing to achieve the bulk of the compliance that would be necessitated by the MRPR standard included as part of their proposal. Direct access providers will be able to qualify for “green” certification based on the acquisition of sufficient RECs, which they will then be able to market as a desirable attribute of the service they offer to their customers. A rating system based on renewable content could be developed in order to provide consumers with a range of alternative “green” electrical services packages and prices.

Green marketing of power is not a major ingredient of any of the other renewable program proposals, although two of the proposals, AWEA et al. and SCE/PG&E, discuss a mechanism by which green marketing techniques could be used to increase the total generation of renewable energy. In each of these proposals, each electric services provider in the state is obligated to acquire RECs representing the MRPR fraction of its energy supply. Green marketing could be used by environmental organizations, for example, to competitively purchase and remove RECs from the system, increasing the total quantity of renewable energy generated to a level that is greater than that necessary to fulfill the state’s collective mandated program obligation. “Green” direct-access providers who purchase some multiplier greater than the MRPR standard of RECs for their portfolio of sources would have the same effect on the collective state market.

C. Areas of Commonality and Difference Among the Proposals

Early in the process, the Renewables Working Group participants realized that it would be unrealistic to set as a goal the reaching of consensus on all or most of the major issues being raised within the group in the time-frame envisioned. The group recognized that there was a wide diversity of interests among the participating parties, and disagreement over the issue of the appropriate methodology that should be used in implementing a program to support renewable energy projects in California. The Renewables Working Group decided to focus its efforts on developing a report that would present a number of comprehensive proposals for the implementation of the CPUC's renewables policy, and discuss the many issues needing to be resolved. Each proposer was required to answer a lengthy list of questions. These questions were designed to help define the scope of each policy proposal and provide comparability across proposals.

While there is no unanimity of opinion on any of the major issues considered by the Working Group, there are some important areas of broad consensus, as well as areas of general disagreement, which are highlighted below.

The Renewables Working Group reached consensus in the following areas:

- Any renewables support program enacted in the state should rely, to the maximum extent possible, on market competition to minimize program cost and/or maximize program performance. Incentives that encourage renewables to participate in the competitive market to the fullest extent possible should be developed. The program should be designed with maximum flexibility in order to facilitate compliance.

- It would be preferable for any renewables support program enacted in the state to be implemented on a statewide, non-bypassable basis. However, there is disagreement among the parties as to whether that can be accomplished within the time-frame envisioned by the Commission for the initiation of electric utility restructuring.

- In order to be eligible for participation in the program, energy produced by renewable generating sources must be used by consumers located in California. However, there is disagreement among the parties as to whether renewable generating sources located outside of California should be allowed to participate in the program (or whether out-of-state sources can be denied the right to participate).

- All of the renewable generating technologies listed explicitly in the California Public Utilities Code, including biomass, geothermal, solar, and wind, should be eligible for participation in a renewables support program. However, there is disagreement as to whether hydroelectric generators should be eligible to participate.

- Regardless of the type of renewables support program adopted, provisions should be included in the program to counter fraudulent activity on the part of any program participant.

- It would be desirable to coordinate with the RD&D Working Group regarding funding and other issues relating to the commercialization of emerging renewable generating technologies.

The Renewables Working Group was not able to reach consensus in the following areas:

- The basic methodology upon which to base a renewables support program. The group considered two basic approaches for meeting the Commission's resource diversity goals: (1) the MRPR, which the Commission described as "...the best approach to meet our resource diversity goals." (p. 150, restructuring decision), and (2) the surcharge-funded production credit approach.

- Among the MRPR proposals, there was agreement that a system of tradable credits should be established. However, the group did not agree on whether to denominate renewable credits using energy (kWh) or capacity (kW) units, nor at what level to set the MRPR.

- For the MRPR proposals, whether renewable generators or utilities/ratepayers should receive the RECs associated with existing renewable generation sold under power sales contracts developed prior to the enactment of any MRPR program.

- All of the MRPR proposals to the Working Group place compliance obligations on electrical services providers to meet the program's requirements. None of the MRPR proposals place compliance obligations on electricity generators. In the surcharge-funded production credit proposal, electric service providers have no explicit compliance obligation, but are instead only required to collect program funding.

- Whether the program should have a cost cap, at what level a cost cap should be set, and whether funds collected as a result of administrative sales of credits at the cap price should be turned back into the tradable-credit market or be administered in other ways.

- Whether the program should focus on the development of new renewable generating sources, or whether it should be used to support both existing and new renewable generating sources. If existing generating resources are eligible to participate in the program, there is disagreement over how to allocate credits for renewable energy that is sold under existing (pre-restructuring) power purchase agreements.

- Whether specific technologies should be targeted for support, or whether all renewables eligible to participate in the program should compete head-to-head. The only technologies for which special consideration is requested are solid-fuel biomass, biogas, and emerging technologies. Some proposals would give special consideration to one or more of these technologies, whereas others propose full head-to-head competition among all eligible renewable generating technologies. In the case of emerging technologies, the group was split over what role a renewables program should play in support of commercialization, or whether commercialization is more appropriately dealt with through the RD&D program, or a combination of both.

- What types of non-central station renewable energy applications should be eligible for participation in the program. There was no consensus on whether UDC-owned distributed renewable generators should be eligible, or whether grid-connected and/or off-grid self-generation should be eligible to participate in the program.

- Whether the fossil-fuel related output from fossil/renewable hybrid generation should be eligible for support within a renewables policy.

- Can the CPUC implement a renewables program based upon existing state law, and/or within the context of electric utility restructuring, or is new legislation required. For example, there was disagreement as to whether or not the Commission could implement an MRPR proposal that imposes an obligation on retail providers other than UDCs.

- What is the most appropriate agency to administer the program, and what type of market structure should be used in the trading and acquisition of renewable energy credits. Issues include the governance of the agency, identification of the specific agency, role of the Power Exchange, ISO, and UDCs, and reliance on the private sector for development of a competitive REC market.

- There was disagreement within the group as to whether or not the program should have a specified sunset date, or whether regular periodic reviews of the program should be conducted.

Chapter 4

PROGRAM PROPOSALS

This section presents the six comprehensive program proposals received from parties participating in the Renewables Working Group and the two adjunct proposals. Five of the six comprehensive program proposals present strategies for the implementation of the minimum renewables purchase requirement included in the CPUC's restructuring decision. The sixth comprehensive proposal is for a surcharge-funded program that distributes renewable production credits on the basis of a competitive bidding process.

Each proposal begins with an interpretation of the Commission's goals and a rationale for the particular proposal. An overview and description of the specific proposal is then provided. Finally, each proposal supplies answers to the fifty one implementation questions listed in Appendix C.

4.1 Comprehensive Proposals With a Minimum Renewables Purchase Requirement

A. Renewables Portfolio Standard

Submitted by the American Wind Energy Association (AWEA), California Biomass Energy Alliance (CBEA), Geothermal Energy Association (GEA), Solar Thermal Energy Alliance (STEA), Union of Concerned Scientists (UCS), and the California Integrated Waste Management Board (CIWMB)

1. Interpretation of Commission's Goals and Rationale for Strategy

This proposal interprets the Commission's December 20, 1995 renewable energy policy decision to mean that implementation strategies should maintain pre-April 1994 (i.e., pre-Blue Book) system resource diversity provided by renewable energy resources and increase the level of that diversity over time, thereby providing new markets for renewable energy. This is consistent with existing statutory authority. To meet that goal, the Commission seeks a market-based approach that does not require centralized decision-making or centralized collection and dissemination of funds. The Commission also seeks to avoid placing investor-owned utilities at a competitive disadvantage in the market.

This strategy, which we call a Renewables Portfolio Standard (RPS), meets these goals by placing, as of January 1997, an equal renewables purchase obligation on all retail sellers of electricity under the Commission's jurisdiction and, with legislation, on all retail sellers statewide.

The obligation begins somewhat below the 1993 level of renewable energy consumption in California and increases gradually over the next few years. Within these levels, retail sellers also have a solid-fuel biomass energy purchase obligation to preserve the existing resource diversity among renewable resources and the associated benefits. The obligation is market-based because it minimizes the regulatory role to that of certifying Renewable Energy Credits, verifying that retail sellers possess the required number of credits for each reporting period, and imposing a significant penalty for non-compliance on retail sellers that fall short. Retail sellers make all decisions about how to comply. The proposed penalty is sufficiently large to ensure full compliance and minimize the need for enforcement action. The cost of the credits is capped to ensure cost containment of this policy.

2. Program Overview and Description

a. Concept

This proposal, termed a "Renewables Portfolio Standard" (RPS), is for a minimum purchase requirement of renewable electricity to be applied equally to all retail sellers of electricity under the Commission's jurisdiction and, with legislation, on all retail sellers statewide. The requirement is to be in place as of January 1997. The definition of renewables is limited to wind, solar electric, geothermal, solid fuel biomass, waste-to-energy, and biogas. Any renewables generating facility may use up to 25% fossil fuel on an annual basis and qualify as a renewable generator. Any greater use of fossil fuel results in pro-rating the renewables output in proportion to the renewable resource fuel used.

This proposal is entirely consistent with the Commission's decisions and orders relating to renewable power. It is also consistent with existing statutory requirements in the Public Utilities Code. When implemented, this proposal will maintain production from renewable energy facilities serving the state at a level slightly less than that which existed in 1993 (prior to the issuance of the initial CPUC deregulation order in April 1994), and increase that level gradually over time.

b. Description of the Minimum Purchase Requirement

The RPS is designed to preserve roughly the existing level of renewable energy generation in California by requiring that retail sellers support a minimum of 11.6% renewable energy (kWh) in their annual sales. The requirement is proposed to increase gradually over time by an amount of renewable energy equivalent to the effective capacity that was set aside for renewables by the Commission in D. 92-04-045. Within the 11.6% requirement is a 2.1% requirement for electricity generated by solid fuel biomass. The separate technology band for solid fuel biomass reflects the desire to preserve the substantial and unique environmental benefits of this industry which stem from its use of biomass fuel, and its higher cost of electricity generation resulting from the necessity to collect, process, and transport that solid fuel, as well as the high cost of its conversion to electrical energy as compared to gaseous or liquid fuels.

The minimum portfolio requirement starts at a level that is less than the amount of energy which can be delivered by the existing renewable energy industry. Renewable generators will have to compete with one another in order to secure a place in the portfolio, since the size of the portfolio is smaller than the ability of the industry to deliver. As a result, competition will be fostered within the RPS which will keep the cost of renewable electricity low. Within the solid-fuel biomass technology band, competition among biomass-fueled generators will likewise keep the cost of that power as low as possible.

c. Renewable Energy Credits

Compliance with the RPS is achieved through use of marketable "Renewable Energy Credits" (RECs), including a subset of "Biomass Energy Credits" (BECs), which are tradable certificates of proof that one kWh of electricity has been generated by the appropriate renewable-fueled source and sold to an end-user in California. Both types of credits are denominated in kilowatt-hours (kWh) and are a separate product from the power itself. The requirement for RECs can be satisfied by ownership of BECs, but not vice versa. Each credit is proof of actual generation and end-use of renewable resource electricity in California not merely proof of capacity.

The sale of RECs is the mechanism by which revenues are transferred from retail sellers to the most competitive renewables generators to maintain their economic viability. The RECs are owned by the renewables generator and may be bundled for sale along with its power, or RECS and power may be sold separately into their respective markets at prevailing market prices. The exception to this is that, during the fixed-price period of a Standard Offer 4 contract, the RECs created by a renewable-resource generator belong to the contracting utility, and are to be sold for the benefit of the ratepayers.

Basing compliance with the RPS on tradable RECs enables retail sellers to develop least-cost power sales portfolios, since they do not have to purchase renewable-resource power. Rather, they can search out the power portfolio which best meets their customers' needs, and then satisfy their minimum purchase requirement through the purchase of RECs. The trading of RECs also creates a cost-reducing competitive market for renewable power since renewables generators will compete to lower the cost of their generation, and therefore the price of their RECS, to assure that their own power and RECs are purchased. These same principles apply to BECs.

This proposal includes a system of cost containment that is distinct from the penalty (which is to ensure full compliance). The "cost cap" establishes an upper limit on the price that retail sellers must pay for RECs and BECs, but is carefully crafted to avoid undermining the market created by the standard and to avoid the need to award funds on an administrative basis.

d. Equity, Efficiency, and Feasibility

Since the benefits of renewable power are shared by all Californians, under this proposal, all Californians will share in the incremental cost of the renewable energy generation serving the state. The cost is shared equitably since all retail providers must purchase their fair share of RECs, a fixed percentage of their total kWh sales. In terms of efficiency, this proposal is consistent with the state's efforts to lower the cost of electricity in California. This is a market-based program; agency-administered support of renewables is unlikely to produce results at lower cost. Retail sellers of electricity have the freedom to build least-cost combinations of power and RECs, and renewable-resource generators have an incentive to drive down costs so their own power and RECs will cost less than the competition.

In terms of feasibility, the REC market concept is patterned after the emission-reduction credit trading program of the South Coast Air Quality Management District's RECLAIM (Regional Clean Air Incentives Market) Program, which has been very successful, using both a large number of private transactions and an annual auction of credits. This proposal also follows the pattern of the SO_2 credit-trading program under the federal Clean Air Act, which has also been very successful.

When renewables become competitive with conventional electricity sources on a direct-cost basis, this program self-sunsets. That is, when the price of RECs falls to zero as a result of rising costs of convention-fuel power and the declining costs of renewable power, the portfolio standard will no longer be needed.

e. Reporting and Enforcement

Reporting is straightforward. Each year, retail sellers document and report: (1) their total retail sales in kWh for the previous year; (2) ownership of a sufficient number of generic RECs; and (3) ownership of a sufficient number of biomass RECs (BECs). On a quarterly basis, renewable-resource generators report and certify the number of RECs created as a result of their generation. Sale of renewable power for end use in California is assumed if the power is sold to an end-user in California, power pools serving California, or retail sellers serving California end-users. At the end of the year, a state agency simply compares the retail sellers' reports with the renewable generators' reports, in much the same manner as the Federal IRS compares taxpayer reports of income and dividends with the 1099 forms filed by the payers of that income and issuers of the dividends.

To provide compliance flexibility to retail sellers, a three-month true-up period is provided at the end of each year during which retail sellers may obtain the required number of RECs or makeup any shortfall. During this period, purchases of RECs can be made from renewable- resource generators that may have unsold RECs, or from retail sellers that have RECs exceeding their requirement. After the true-up period, an automatic penalty for non-compliance is assessed at 6 cents for each REC that the retail seller falls short. This penalty is estimated to be about three times the cost of compliance--high enough to encourage full compliance, yet not so high as to encourage litigation.

3. Implementation Questions

a. What Is the Obligation?

a.1 How is "renewables generation" defined for purposes of qualifying for tradeable "renewable energy credits" (RECs) under this proposed program? Does existing and incremental utility-owned renewable-resource generation qualify for RECS?

Given the Commission's goal of maintaining system diversity, the definition of qualifying renewable resources is limited to those resources (and associated technologies) that bring significant public benefits, including economic, environmental, and price stability benefits and fit several, if not all, of the following criteria: (i) are not technologically mature; (ii) are not fully commercialized, i.e., limited market share; (iii) have significant development potential; and (iv) may have difficulty competing in short-term, price-focused markets. The resources that fit these criteria are: biomass (including solid-fuel biomass, solid waste-to-energy facilities, landfill gas, and anaerobic digester gas); geothermal; solar (including solar thermal electric and photovoltaics); and wind.

The only renewable resource that is excluded from qualification for RECs based on these criteria is hydropower. Hydro was separately addressed by the Commission's December 20, 1995 Decision. Hydro brings some public benefits in avoiding air emissions and wastes from conventional power plants, and some hydro plants (especially those with high environmental mitigation costs) may have difficulty competing in dry years. However, hydro is technologically mature, is fully commercialized (representing a significant share of the California energy market), and has limited development potential. In addition, including hydro in the RPS program would create several practical problems: (a) output from the large Northwest base of hydro could potentially be rerouted into the California market and capture the market created by the RPS; (b) the large year-to-year fluctuations in hydro output would make it difficult for retail suppliers to meet a fixed standard each year and at the same time provide a predictable market for renewables; and (c) many hydro facilities have more than one use and have obtained government subsidies. Therefore, it may be difficult to avoid cross-subsidizing irrigation, recreation, flood control, etc., through payments to hydro via the RPS.

Those facilities that fit this definition of renewables and are consistent with ownership limitations on distributed generation (see question a.9) can qualify for credits. This also relates to credit allocation (see question c.1).

a.2 What are Renewable Energy Credits? How do they relate to energy portfolio management?

Renewable Energy Credits ("RECs") are central to the RPS. A REC is a tradable certificate of proof that one kilowatt-hour of renewable resource electricity was generated. Thus, RECs are denominated in kilowatt-hours (kWhs). A REC is created when: (1) a qualifying renewable-energy resource generates one kWh of electricity; (2) that kWh is ultimately sold at retail in the state; and (3) a satisfactory verification of (1) and (2) is made.

A REC is a separate product from the renewable power itself. Its purposes are to provide the means for retail sellers to demonstrate achievement of the portfolio standard, and to provide retail sellers with a cost-reducing alternative to achieving the standard compared to reliance solely on power purchases. RECs are also the means by which sufficient funds will be provided to renewable generators so as to make viable the level of renewables generation required by the RPS. Every retail power supplier would be required to possess RECs equivalent to a determined percentage of its total annual kWh sales. Retail sellers make all decisions about how to comply. They can purchase RECs when they purchase renewable power (a "package" of RECs and power), or they can purchase RECs separately either directly from a renewables generator or from the REC market. Thus, retail sellers can decide whether to build a renewable energy facility, purchase renewable power bundled with RECs, or buy credits separately. (Note that, if UDCs are not allowed to own generation, they would not have the option of building/owning renewables.) The REC system provides compliance flexibility and avoids the need to "track electrons."
Under this program, retail sellers make all decisions relating to the type of renewable energy to acquire, the price paid, the contract terms offered, and whether to enter into long-term REC and/or renewable power purchase contracts or to purchase these commodities on the spot market.

A subset of RECs, "Biomass Energy Credits," or BECs, would be created to implement a solid-fuel biomass "technology band." All of the above principles would also apply to BECs. Here-in-after, BECs are generally included in each reference to RECs. As described in item b.3. below, the prices of the RECs and BECs are capped.
a.3 How is a diversity of renewables encouraged?

A diversity of renewable resources is encouraged because retail sellers and investors are likely to seek out the most cost-effective technologies and technology applications, thereby taking advantage of the most cost-effective applications of each resource (i.e., the low-cost end of the supply curve for each resource). Because, with the exception of solid fuel biomass, the cost of many renewable technologies (new wind, geothermal, and landfill gas facilities and existing solar thermal electric and solid waste to energy facilities) are in the same competitive range, the market is likely to value a diversity of resources and technologies. This should also encourage niche applications of renewables, such as distributed applications of photovoltaics. In addition, the technology band for solid-fuel biomass resources (not including solid waste-to-energy), which would otherwise have difficulty competing with other renewables, will encourage these resources.

Beyond these means, further diversity is encouraged through commercialization programs (see next question).

a.4 Are currently-high-cost technologies or pre-commercial technologies fostered by this program?

This strategy does not envision the RPS as a technology commercialization program. Thus, the proposal only includes one technology band for solid-fuel biomass, which has a significant existing base of investment and capacity. However, the RPS helps to close the gap between the cost of pre-commercial technologies and the market price. As a result, technology commercialization program dollars, both state and federal (if invested in the state), will go further.

In addition, to support pre-commercial, very high-cost technologies that have significant potential for cost reduction, this strategy recommends that : (i) RD&D programs be expanded to "RDD&C" programs, to include support for commercialization activities for pre-commercial renewable technologies, and that the funding level be expanded accordingly; (ii) customer-side applications of renewables be supported through energy efficiency programs, and that funding levels be expanded accordingly; and (iii) distributed renewables applications be supported through the pass-through of area-specific T&D benefits as an incentive to customers and third parties to invest in distributed generation. When such technologies become closer to market price (including the value of RECs) as a result of such programs, the technology can compete more successfully in the RPS market, and technology bands could be considered.

a.5 How is renewables self-generation handled? Is self-generated renewable energy eligible for RECs, or for other means of support?

Off-grid renewable self-generation applications would not qualify for RECs for several reasons: off-grid applications are not metered or sold at retail, and thus verification of production would be difficult; and most off-grid self-generation applications are already competitive as compared to T&D line extensions.

Surplus generation that is metered and sold at retail from customer-owned, grid-connected renewable facilities could be eligible for RECs. However, the power produced by these systems for on-site consumption would be administratively difficult to verify for the purpose of qualifying for RECs, which are geared to kWh sold at retail. Thus, this application would be better supported through energy efficiency programs.

Third-party-owned, on-grid generation connected on the customer side of the meter could qualify for RECs, provided the power is sold at retail. Power consumed on-site would be supported through energy efficiency programs.

a.6 How are hybrid fossil-fuel/renewable-fuel facilities handled?

Renewable generators using up to 25% fossil fuel would fully qualify as renewable. For generators using more than 25% fossil fuel, only the renewable-fueled fraction would qualify.

a.7 Does out-of-state generation qualify for RECs? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

Out-of-state renewable generation that is sold to California end-users would qualify for RECs. Out-of-state solid-fuel biomass generation, however, would not qualify for BECs. Proponents of this strategy believe that the Commerce Clause of the federal Constitution would prevent the state from limiting qualifying renewable facilities to those located within the state[3] with the possible exception of solid-fuel biomass, which is associated with several benefits (e.g., diverting wastes from in-state landfills and prevention of local air pollution created by open agricultural burning) that may not be fully realized without an in-state requirement for these facilities. The in-state renewable energy industry is likely to fare well in competition with out-of-state resources (provided hydropower is excluded), but an in-state restriction for solid-fuel biomass can ensure that the unique in-state benefits of solid-fuel biomass are fully captured.

a.8 If hydro is included, how are practical issues associated with hydropower handled?

Hydro is not included for the reasons stated in question a.1, above.

a.9 How is utility-owned distributed renewable generation handled? Is it eligible to receive RECs? Does the proposal permit RECs to accrue to distributed or other renewable applications that may involve the cross-subsidization of generation with T&D savings, or vice versa? Does the proposal permit or prohibit distributed or other utility-owned renewable power not sold through the power exchange to receive RECs?

The Commission needs to address the market power, self-dealing, cross-subsidization, and functional unbundling issues associated with UDC ownership of distributed generation before such ownership is allowed. UDC ownership could also be inconsistent with the Commission's requirement that all utility and affiliate power be bought and sold through the Power Exchange. Until such a determination is made, UDC- and utility Genco- and affiliate-owned distributed renewables should not qualify for RECs.

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3 See Kirsten Engel, "The Federal Constitution and State Implementation of Renewables Portfolio Standards: An Analysis of Commerce Clause Issues." Posted on the Renewables Working Group web site (http://www.energy.ca.gov/energy/restructuring).

a.10 What is the level for the requirement? How does this level relate to the level of renewables from 1990 to the present? Does the level of the requirement increase over time, and, if so, at what rate?

The overall level of the RPS would be set at approximately 90% of the amount of renewable energy delivered in California in 1993 and would rise 0.2% each year beginning on January 1, 1998, until an additional amount of renewable energy, equivalent to the renewables set-aside of 297.5 MW, as set forth in D. 92-04-045, is achieved. Incorporated in these levels would be a solid-fuel biomass requirement, set at a level approximating 80% of all solid fuel biomass generation delivered in California in 1993. According to data provided by the California Energy Commission (CEC), combined with industry figures for 1993 solid-fuel biomass production (CEC figures are not available for solid-fuel biomass), total renewable energy (as defined above) generated for California use as a fraction of total retail sales appears to be about 12.9%. Thus, the overall standard would be set at about 90% of 12.9%, or 11.6%. The biomass standard would be set at about 80% of 1993 solid-fuel biomass production, or 2.1%. The 2.1% biomass technology band is included in the overall 11.6%; the two are not additive. The 11.6% would rise over time by 0.2% per year, while the 2.1% biomass technology band would not.

These levels are set below 100% to ensure that price competition is achieved at the outset of the policy. The year 1993 is chosen because, in 1994, restructuring activities caused considerable uncertainty that contributed to the closure of several renewable facilities. As the requirement rises over time, renewables developers have adequate lead-time such that competition will occur.

Note that the actual percentage requirement will vary depending on the universe of retail sellers covered. If the RPS is applied by the Commission to entities under its jurisdiction, the above figures would translate into a higher starting figure than if the RPS is applied to all retail sellers statewide. Also note that, as growth in end-use sales occurs, this absolute amount of renewables generation required under the standard will rise.

a.11 Describe how, if at all, the compliance obligation adjusts during a transition period.

No transition period is proposed, and none is required because the RPS is based on the purchase of RECs and BECs, not on the purchase or ownership of renewable power per se.

a.12 Does the proposal include a uniform requirement for all electric providers, including utilities, on a statewide basis?

Yes. This proposal supports the Commission's stated preference that the obligation apply equally to all retail sellers. Legislation would be required to extend the RPS to municipal utilities, special districts, etc. A uniform requirement is reasonable for two reasons: (1) The benefits of renewables accrue largely to the economy and environment of the entire state; and (2) Setting different levels for each entity, based on its current amount of portfolio diversity, and adjusting those levels yearly to achieve uniformity would be administratively cumbersome.

a.13 What is the time-horizon for the program?

There need be no specific sunset provision, as this policy is inherently self-sunsetting. That is, when market and renewables prices equilibrate, the value of RECs will fall to zero. At such time, suspending the standard could be considered. Cost savings will be achieved through certainty and stability of the standard, which will enable long-term contracts and lower-cost financing (for new projects and for repowering existing projects). The ability to obtain financing will foster competition to provide renewable power at the lowest possible cost. Without policy stability, financing costs (and thus the cost of renewables) will be higher, or renewable energy projects will be unable to obtain financing.

a.14 Is the requirement established on a percentage of megawatts or percentage of megawatt-hours basis?

The requirement, and RECs, are based on kilowatt-hours delivered to ensure that renewables generation has actually occurred, and to serve as an incentive for maximum facility productivity. Environmental benefits from renewable energy occur only with generation of power, not from construction of capacity.

a.15 Does the proposal establish floors for certain technology types? What is the rationale for a technology floor, if proposed?

Yes. As mentioned in the answer to questions a.2 and a.3, a technology band would be established for solid-fuel biomass facilities. The rationale is that these facilities represent a substantial existing capacity base which is associated with a broad array of unique and quantified benefits, including diversion of wastes from landfills, prevention of open agricultural burning, and forest management benefits. Costs of collecting, processing, and transporting solid fuel are unique to solid fuel biomass plants among the renewables. These facilities are having difficulty surviving under current market conditions, and are unlikely to be able to compete successfully with other renewable resources due to these fuel-related costs. Loss of this industry would result in increased uncontrolled agricultural waste burning and associated air pollution, increased volume of wastes to landfills with the associated difficulties of mitigating problems of waste disposal such as methane gas and leachate generation, increased forest wildfire danger, poorer watershed management, and worsened forest health.

As mentioned in the answer to question a.10, the solid-fuel biomass technology band would be set at a level substantially below the level of capacity operating in 1993 (and still less than current operable capacity) to ensure competition among biomass facilities and limit costs associated with this technology band.

b. Where Is the Obligation to Comply?

b.1 On whom is the requirement applied? Is the requirement applied only to entities under the Commission's jurisdiction, or is it applied statewide?

If implemented by the Commission, the requirement would be applied to investor-owned utilities, direct access suppliers, and grid-interconnected self-generators transmitting power to another location. Legislation would be required to apply the standard to municipal and cooperative utilities and special districts. This proposal supports statewide application, but, in the absence of legislation, urges implementation by the Commission by January 1997.

b.2 Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences?

The REC purchase obligation applies equally to all retail providers.

b.3 What is the penalty for non-compliance? Should this penalty be interpreted as a cost-cap for the program?

This proposal includes distinct penalty and cost containment methods. Cost containment is described in question e.2. A penalty of 6¢ (indexed to inflation) would be imposed for each REC or BEC that a retail supplier fails to turn in at the end of a three-month "true-up" period following each annual reporting period. This is estimated to be 3-4 times the cost of complying with the program.

This penalty is intended to be high enough to ensure full compliance and to avoid costly enforcement measures. It is modeled after the federal SO_2 allowance trading program, under which an automatic $2,000/ton penalty (indexed to inflation) is imposed for each excess ton of SO_2 produced. SO_2 credits are trading currently at about $150 each, though costs were originally projected to cost between $500 and $1500. A utility that does not comply also has its allowance holdings reduced in the next year by one allowance for each excess ton of sulfur dioxide emitted.[4] Because of the high penalty associated with noncompliance under the SO_2 allowance program, which took effect in 1995, the EPA anticipates full compliance and does not expect to take even a single enforcement action.[5] Another similar program is NEPOOL's capacity reserve requirement, under which each participant is fined $105/kW-year for capacity shortfalls. This is well in excess of compliance costs, and has successfully deterred non-compliance (though the fine has been assessed and paid on several occasions).

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[4] U.S. General Accounting Office. *Air Pollution: Allowance Trading Offers an Opportunity to Reduce Emissions at Less Cost*. GAO/RCED-95-30. December 1994

[5] Phone conversation with Joe Kruger, Chief, Energy Efficiency Section, Acid Rain Division, Environmental Protection Agency, Washington, D.C. (May 2, 1996). EPA is in the process of verifying 1995 compliance with the program.

Thus, the RPS penalty is not intended to act as a cost cap, because it exceeds expected costs. Like the SO_2 program, this policy is intended to be self-enforcing by setting the penalty at a level high enough to ensure that the policy goals are met without resorting to administrative and enforcement measures. In addition, encouraging full compliance with a high penalty will ensure that an active credit market is created and that retail sellers are engaged in thinking about how to incorporate renewables into their resource portfolio at least cost, instead of seeking ways out of the program. On the other hand, the penalty is not so high as to be unduly punitive, and can easily be avoided by purchasing RECs to correct any shortfalls during the true-up period.

Though virtually no penalties are expected to be collected, in the event that a few penalties are incurred, this money could be allocated to the agency that administers RDD&C to help fund the commercialization of emerging renewable energy technologies.

b.4 How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

Compliance of retail sellers is determined by demonstrating ownership of sufficient RECs in relation to electricity sales. This could be done through an electronic system as follows. (i) A renewable facility owner generates credits (by generating renewable power) which are posted by the administering agency into an electronic account for that owner, and so forth for all owners. (ii) Retail Seller Z purchases RECs from Owner A. Both sign a form requesting the administering agency to transfer the purchased number of RECs from Owner A's account into Seller Z's account. (iii) At the end of the annual reporting period, the agency informs all retail sellers of their account status and asks retail sellers to document their total kWh retail sales. At the end of the three-month true-up period, the required number of RECs are removed from each retail seller's account and retired. (iv) For retail sellers who have insufficient credits in their accounts, the agency imposes the per-REC penalty.

The administering agency and enforcement actions for non-payment of penalties would vary depending on whether the RPS is applied by the CPUC or applied statewide. If applied by the CPUC, then the CPUC would administer the program (unless it were delegated to the California Energy Commission). Penalties could be imposed on delinquent direct access sellers and self-generator-wheelers as a condition of being licensed by the CPUC to sell in the direct access market, and on utilities through the PBR mechanism. If the RPS were applied statewide via legislation, then the administering agency would be the CEC, and the legislature would authorize the CEC to impose and collect penalties. The Attorney General would handle seriously delinquent accounts and criminal behavior. The CPUC could revoke licenses if retail sellers fail to pay assessed penalties. However, it is emphasized again that enforcement actions will be rare if the penalty significantly exceeds the cost of compliance, as proposed.

b.5 What provisions add flexibility to compliance, if any?

As indicated in the answer to question b.3, a three-month "true-up" period would be provided to retail sellers. In addition, such sellers could "bank" credits in their REC account for 15 months, i.e., through the true-up period for the following year. Finally, since renewable resources depend on the natural availability of resources, extended true-up periods could be provided to respond to extreme deviations in the expected output of these resources ("force majeure" situations). (Note that, if hydropower is excluded, these fluctuations should not affect the entire REC market, but may affect individual retail sellers who have contracted for RECs from certain facilities.) If credits are unavailable in the market for other reasons (e.g., rapid growth in retail sales), true-up periods could be extended until RECs become available.

b.6 How does the program ensure that the policy and its costs are non-bypassable, such as the CTC or the Public Goods surcharge?

If the program is implemented by the CPUC, then costs would be imposed on a non-bypassable basis by requiring all entities under CPUC jurisdiction to comply with the program. Penalties would be imposed as described in the answer to the previous question.

If implemented statewide via legislation, the program would be applied uniformly to all retail sellers. "Retail electricity supplier" should be defined to mean: "any entity that sells electric power not for resale to an end-user, including but not limited to electricity providers that are affiliates or generating companies of investor-owned utility distribution companies, municipal utilities, cooperative utilities, local governments, special districts, or direct access suppliers." "End-user" should be defined to mean: "an entity located in the State that purchases electricity based on metered use but does not resell electricity based on metered use." These definitions cover all situations, including such unique ones as port authorities and malls. Penalties would be enforced on any entity that fails to comply.

c. How Are Renewable Energy Credits Initially Allocated?

c.1 How are RECs generated from existing renewable facilities (QFs and utility-owned) initially allocated? What impact does the initial allocation have on whether a vigorous market for RECs, characterized by many buyers and sellers, forms?

Existing renewable QF projects will own the RECs they generate, except during the fixed-price period of ISO4 contracts. RECs generated during the fixed-price period will be auctioned off by a marketing agent designated by the CPUC, and proceeds will be applied to reduce the CTC, thus benefitting ratepayers. It is necessary to use a marketing agent with no interest in the REC or power markets so that RECs are auctioned off fairly. Otherwise, utilities will have a market advantage over competing retail sellers by having preferential access to these RECs, potentially at no cost. During the fixed-price period, utilities could certify QF output as RECs and turn them over to the marketing agent. After the fixed-price period, as a result of competition between REC sellers, capacity payments made to QFs under Standard Offer contracts will directly contribute to reducing the cost of RECs, just as will the energy payments made under those contracts.

RECs produced by existing utility-owned renewables facilities will be owned by the utility. Proceeds from any RECs that are sold would be applied to the CTC, thus benefitting ratepayers. At such time as utility renewables facilities are sold or spun off to an unaffiliated entity, the credit rights will accompany the sale, and should be valued as a part of the sale.
Allocating credits in this way will facilitate the creation of a single market for renewables (including new and existing projects) so that the lowest-cost projects will survive. It will also avoid potential market power situations by creating a large number of REC sellers, which will create a competitive market for RECs. As more retail suppliers enter the California market, the number of REC buyers will also increase.

QFs are entitled to the RECs they generate after the fixed-price period because they took the investment risk, and many are, indeed, now facing that risk. The objective of the RPS is to support the existing level of diversity, thus it makes sense for these projects to own the credits. Because the risk of utility projects is passed through to ratepayers (witness the full-cost recovery through the CTC), RECs generated by utility-owned resources should flow to ratepayers.

c.2 What is the relationship between the allocation of RECs and the CTC or Public Goods Surcharge? Will RECs accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid or otherwise avoid part or all of the CTC and Public Goods Surcharge?

See answers to previous question and question a.5.

c.3 If customers or ratepayers are initially allocated RECs, how are the credits administered?

See answer to question c.1.

c.4 How would the proposed credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make buyouts more or less cost-effective to ratepayers?

The proposed REC allocation (to ratepayers during the fixed price period of ISO4 contracts and to QFs thereafter) will neither encourage nor discourage QF contract holders from negotiating contract buyouts. To encourage or discourage buyouts means that one party will be placed in a more favorable negotiating position than the other party. This is not an intended result of the RPS. By keeping both parties neutral, negotiations can and will go forward without regard to the RPS or the value of the RECs. Should the CPUC desire to encourage buyouts, it could do so by establishing a definitive basis for such negotiations between the parties. Creating a "tilted" playing field is not an acceptable solution.

c.5 How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

Because competition is built into this program (see answer to a.10), and because the initial allocation of RECs creates dozens of REC sellers, a very competitive market for RECs will exist because everyone will want to sell all of their RECs. This proposal significantly minimizes the potential for windfall profits by allocating to ratepayers the RECs generated by QFs during their fixed-price period. We are not aware of any renewable generators that would be profitably sustained at current market prices without RECs. Markets work because they reward the most efficient producers. Therefore, the REC market will work to foster the most cost-competitive renewable energy projects, which will minimize the potential for windfall profits.

c.6 Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

While the RECs will increase the value of utility-owned renewable resources, the proposal neither encourages nor discourages divestiture by the utilities because the increased value realized upon a sale would accrue to the ratepayers, not stockholders, per the CPUC's 12/20/95 decision. It is possible that the value of the RECs might encourage utilities with renewable resource assets to retain those assets in order to meet the RPS.

d. How Is the Program Administered?

d.1 What agency certifies the RECs, and what does the certification process entail?

If the RPS is implemented by the CPUC, the CPUC could either (a) handle REC certification, (b) delegate REC certification to the CEC, or (c) contract REC certification out to a neutral third party, perhaps a private entity. If the legislature adopts a statewide program (which is the preference of the proponents of this strategy), the program could be administered by the CEC or contracted out to a neutral third party.

Under the certification process, which would occur quarterly, renewable energy generators would certify their output (certification takes place after generation has occurred) by filling out a form provided by the administering entity. (A certification fee could be charged for the sole purpose of covering reasonable costs of certification.) The form would ask for: the name of the company; identification of the unit (e.g., location or I.D. number); the type of facility (checking off from a menu of options corresponding to the qualifying types of facilities); the amount of power generated and the period in which the power was generated; and who purchased the power from the renewables generator. In some cases, data would be requested to assist in the tracking of where end-use of the power occurs.

As a simplifying measure, qualifying renewable power sold to any purchaser on the following list should automatically lead to certification of the RECs: an end-user located in California; power pools serving California; and specified retail sellers serving end-users in California. Though this simplification does not guarantee that all REC-certifying renewable power is contractually linked to California end-users, it is a reasonable simplifying measure.[6] Potential purchasers of renewable-resource power not on the list, such as wholesalers or aggregators serving more than one state, would not be required to participate in REC certification. REC certification based on power sales to these entities could occur only if a generator can arrange with the purchaser to provide adequate proof that end-use took place in California.

d.2 What mechanisms are proposed for trading of RECs? How do the trading mechanisms relate to the initial allocation of RECs?

Other than auctioning off certain RECs (see answers in section c), no mechanisms are proposed for trading RECs. Bilateral contracts and specialized REC markets can be expected to occur without regulatory intervention, as has taken place in similar markets for tradable permits and obligations (e.g., NOx markets under RECLAIM, and SO2 markets under the Clean Air Act.)

d.3 What mechanisms are proposed for program oversight and mid-course corrections?

The implementing agency can adjust the rules as program experience is gained to increase efficiency and better meet the policy goals. The agency should devise measures such as number of sales, number and distribution of REC purchasers, length of time required to verify RECs, cost of certification, etc., to gauge the success of this policy and help to identify areas for improvement in implementation.

d.4 What agency monitors and enforces compliance with the program, and how is it carried out?

See answers to questions b.3, b.4, b.5, and d.1. Whether the agency is the CPUC, the CEC, or other neutral third party, the same entity should both verify the creation of RECs and verify compliance. This agency would also issue RECs at the cap price when required (see e.2. below), and purchase above-cap RECs as appropriate. This will facilitate the verification of RECs, the tracking of RECs, and enforcement on retail sellers. It should also improve administrative efficiency.

e. Cost-Related Issues

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[6] For more detail on this point and related issues, see March 6, 1996, memo from Brent Haddad posted on the Renewables Working Group web site (http://www.energy.ca.gov/energy/restructuring).

e.1 What are the costs associated with the program, and who pays?

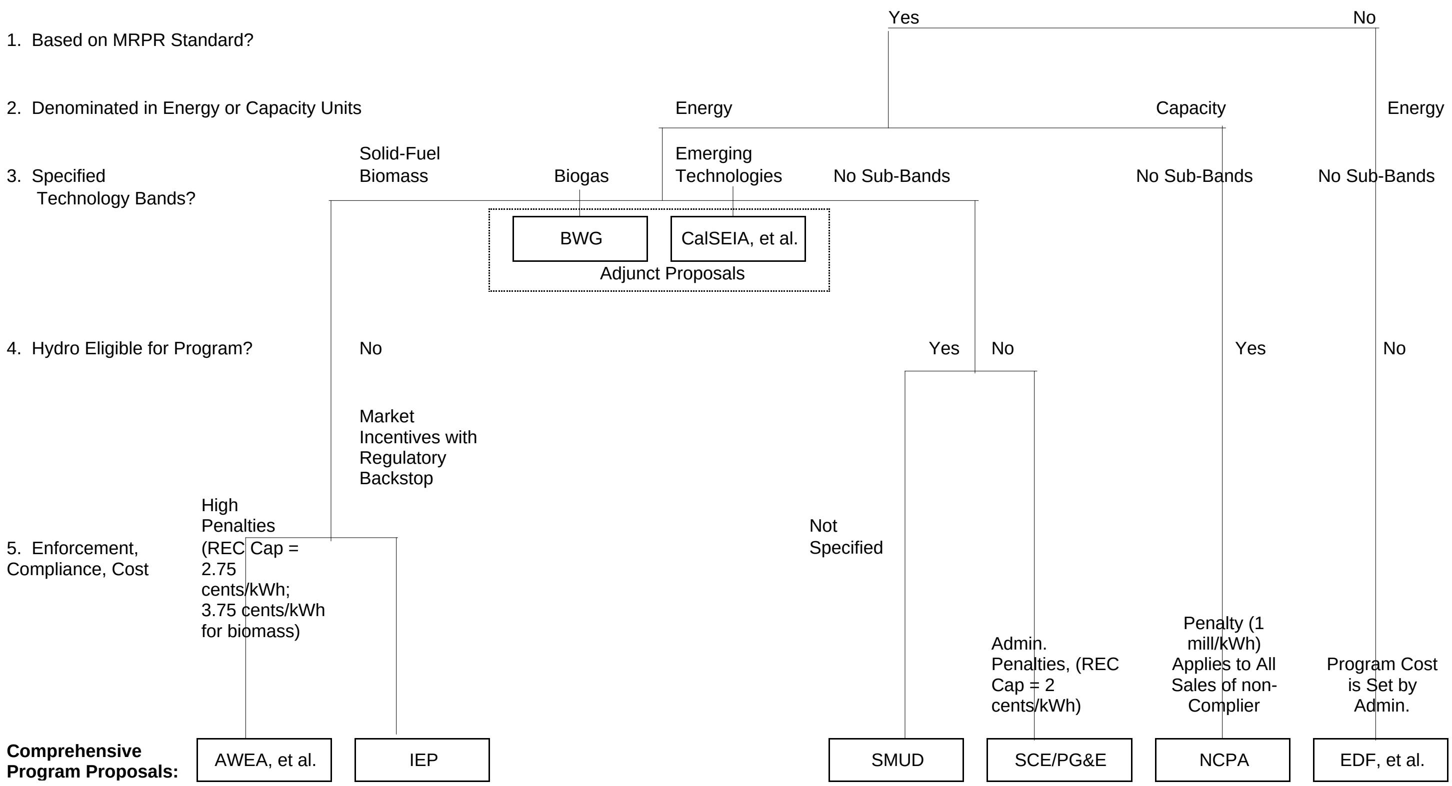
It is acknowledged that the cost of renewable power is above current marginal-cost market prices, since that market is dominated by inexpensive natural gas-fueled generators. It is not, however, possible to state what the price of electric generation will be in a restructured electric industry in which the market price reflects the total cost of generation. Current short-run avoided cost prices do not accurately represent the true cost of electricity, and long-run avoided cost will not be apparent until after the CTC collection period ends. Moreover, even in a truly competitive market, total-cost market prices will not reflect the full value of fuel diversity, environmental costs, and in-state economic benefits without policy measures such as the RPS. Below we show that expected benefits of this proposal outweigh expected costs, even using current marginal-cost prices.

COSTS: Keeping in mind that current market prices do not reflect total long-term costs, back-of-the-envelope estimates can be made using these short-run prices (see attached spreadsheets). If RECs are assumed to sell for 1 cent to 2 cents per kWh above current market prices and solid fuel biomass RECs (i.e. BECs) are assumed to sell for 2 to 3 cents above current market prices, then the first year (assumed here as 1997) of the RPS can be estimated to cost between $152 million and $298 million. This is 0.61% - 1.03% of the state's total electric bill ($25 billion), and translates to an added cost of between 35¢ - 68¢ per month for the average California household. Program costs would increase annually as the QFs reach the end of the Standard Offer-4 contract fixed-price periods and enter the REC/BEC market. On the other hand, and counter to this estimated increasing program cost, program costs would tend to decline over time as the current power glut dries up, nuclear plants are paid off, market prices rise, and the prices of renewables fall due to competition, technology and project improvements, greater economies of scale, and production economies. Thus, by 2001, if the cost of RECs declines to 0.5 to 1.0 cents and the cost of BECs declines to between 1.0 and 2.0 cents, the program costs can be expected to increase only to a level of between $155 and $311 million per year, even as the level of the standard increases.

Even these, however, are overestimates, because they do not count the proceeds from RECs generated by renewable QFs and sold for the benefit of ratepayers during the fixed-price period of the renewables' ISO4 contracts. It should also be noted that the total cost of diversity provided by renewables under this program will be substantially less than what it has cost over the previous decade as a result of dramatic declines in the cost of renewable technologies and the end of the fixed price periods of ISO4 contracts (in contrast to experience with nuclear technology).

BENEFITS: The benefits that accrue from renewable energy and the associated industries far exceed these costs. These benefits total $829 million - $1.28 billion annually and include:

Figure 3-1: Classification of Program Proposals



Note: Adjunct proposals can be attached to any of the comprehensive program proposals

$383-844 million in clean air benefits (using adopted CPUC emissions values); $137 million in fuel diversity benefits; $38 million in wildfire risk reduction benefits; $60 million in landfill diversion benefits; $51 million in local property taxes paid; and a $160 million payroll. (See attached spreadsheets.) Without the RPS, some these in-state benefits would be lost to in-state generators that provide fewer jobs/MW and to out-of-state generators. If fuel price and environmental regulatory risks should materialize, this RPS program could result in even more substantial benefits to the state.

e.2 What cost-containment measures, if any, are provided?

This proposal includes a system of cost containment that is carefully crafted to avoid undermining the market created by the standard. This cost cap method also avoids the need to disperse funds through administrative means. In order to establish an upper limit on the price of RECs and BECs, caps are set on the price that retail sellers must pay for the credits. For RECs, the cap is set at 2.75 cents and, for BECs, the cap is set at 3.75 cents. These caps are somewhat higher than the expected marginal cost of credits, but considerably less than the penalty.

If, in its solicitation of RECs and BECs, a retail seller is unable to purchase the number of credits it needs at the cap price or below, and this is confirmed by the administering agency by reviewing prices in the market for RECs, then the agency issues the number and type of "proxy" credits the retail seller requires for compliance, charging the seller the cap price. This activity would take place for each retail seller needing credits towards the end of the "true-up" period each year. At this point, each retail seller has met its obligation under the RPS, and the administrator has a sum of money. The administrator takes this sum of money and purchases credits in the market, lowest prices first, until the funds are expended. Although this process may result in supporting less than the number of renewable kWh necessary to achieve the standard (this is the nature of a cost cap), it assures retail sellers and consumers of a cost of compliance that cannot be exceeded; the expected cost is clearly below this maximum. Marginal-cost competition is preserved because renewable energy generators will compete for assured sale of their credits both below and above the cap price. This will serve to keep the price of RECs and BECs as low as possible. Our recommended cost cap level should result in the administrator never having to perform this cost cap function.

There are several ways in which this policy assures least-cost achievement of the Commission's renewables policy goals. Cost savings are first achieved because the certainty and stability of the RPS policy will enable long-term contracts and financing for the renewable power industry, which will, in turn, lower renewable power costs. Least-cost compliance is encouraged through the compliance flexibility provided to retail sellers, who can compare the cost of owning a renewables facility to the cost of a REC/renewable power purchase package and to secondary-market RECs. Finally, since retail suppliers will be looking to improve their competition position in the market, and since all must meet the standard, each supplier will have an interest in driving down the cost of renewables, perhaps by lending their own financial resources to a renewables project, by seeking out least-cost renewables applications, or by entering into long-term purchasing commitments. This fosters a "competitive dynamic" that is not achieved with policies that involve direct subsidies to renewable generators without involving the rest of the electric industry.

e.3 If the program utilizes floors for certain technology types, what are the implications in terms of costs and benefits?

See answer to question e.1.

e.4 Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

The RPS is to be applied to all retail sellers, hence all consumers, equally. However, applying the RPS policy on a uniform basis could lead to cost-shifting from those utility customers who are currently supporting a high level of renewables (PG&E, SCE and some municipal customers) to those utility customers who are supporting lower levels of renewables (SDG&E and some municipal customers). Specifically, those customers supporting a renewables portfolio in excess of the required percentage of their power sales will have an opportunity to reduce their renewables costs, while others will be required to increase their investment to the required level through acquisition of RECs. Though this could cause some near-term rate impacts, a uniform standard can be justified by the fact that: (a) many of the benefits of renewables accrue statewide, and those customers who have not paid for these benefits in the past have to some extent been "free riders" for the past decade; (b) the cost of renewable energy has declined dramatically and will be substantially less than what has been paid for renewables in the past; and (c) it would be administratively cumbersome to transition from a non-uniform standard to a uniform one.

e.5 How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities encouraged?

See answers to questions a.10, a.15, c.1, and e.2.

e.6 What implications, if any, does the proposal have in defining the roles of the UDC and of competitive suppliers of electricity?

No implications. The proposal will not encourage any change in the role of the UDC other than what is envisioned in the restructuring decision.

e.7 What is the consistency of this proposal in relation to cost-related guidance provided by the CPUC roadmap?

If this proposal causes some rate impacts for utilities that currently would not meet the RPS, the Commission may have to accommodate such impacts as necessary to implement its renewables policy.

f. How Does the Program Fit with Other Aspects of Restructuring?

f.1 Is the program compatible with the existence of an ISO? A Power Exchange? A direct access market? Is the proposal consistent with the Commission's vision of the role of the Power Exchange and ISO?

Yes.

f.2 Is the proposal dependent in any way on the Power Exchange or ISO? Is so, are any additional protocols necessary?

No, the proposal does not rely on the Power Exchange or ISO for implementation, and no protocols are necessary specifically to implement the RPS policy. However, rules to accommodate renewables, especially intermittent renewables (e.g., in Power Exchange bidding rules) will facilitate least-cost compliance by reducing artificial market barriers.

f.3 Does the proposal involve conflicts of interest between distribution and competitive retail services? If so, how are they resolved?

No, the UDC is treated the same as all retail sellers. The Commission needs to decide whether UDCs will be allowed to own distributed generation, which may involve conflicts of interest between distribution and competitive retail services.

f.4 How does the program avoid conflicts of jurisdiction between state and federal levels?

The RPS avoids state/federal jurisdictional conflicts by applying the standard to retail sellers, which are clearly under the state's jurisdiction (as opposed to wholesale generators and power pools).[7]

f.5 What is the relationship between the proposal and direct access and "green marketing"?

By developing a renewables base and a solvent renewable energy industry, and by addressing "free rider" problems by spreading the cost of a minimum level of renewables over all consumers, individual consumers are more likely to have the opportunity to support a larger fraction of renewables through their choice of supplier because those suppliers will exist. In addition, the renewables industry will be healthy enough to engage in green marketing, which will entail high

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[7] See Scott Hempling and Nancy Rader, "State Implementation of Renewables Portfolio Standards: A Review of Federal Law Issues" (January 1996). This paper is posted on the Renewables Working Group web site.

transaction costs in reaching prospective customers. Green marketers will also have greater flexibility to achieve their advertised green portfolio targets. The RPS policy will help to reduce the cost of renewables, which will make them more attractive to consumers and retail sellers.

Green marketing could involve bundling RECs with the power sold, so that customers desiring green power may, in effect, retire the RECs, thereby contributing to a higher amount of renewables in the overall resource mix of the state. (Also see section f.8.ii on consumer protection and education.)

f.6 What is the relationship between the proposal and PBR? Does the proposal place RECs under PBR, or exclude RECs from PBR?

There is no explicit relationship between the RPS policy, RECs and PBR. However, as for any other utility cost, PBR can be used to reward utilities for efficiently acquiring RECs or penalize them for inefficiency.

f.7 Does the program create any potential market power problems involving the generation market or RECs?

The allocation of RECs proposed in section c.1 eliminates the potential for market power problems by creating dozens of REC sellers. There are currently a substantial number of renewable generators, with no one or two individual companies possessing a significant share of renewables capacity. Market power problems could exist on the REC purchase side, however, if the three IOUs are the only purchasers of RECs, especially in the first years of direct access. Expanding the RPS, by legislative action, to all retail sellers in the state will alleviate this market power possibility.

f.8 Does the proposal relate to any consumer protection or consumer education efforts?

i. Rules for new entrants. Compliance with this policy should be a condition of selling power at the retail level. Ideally, all retail suppliers should be licensed, so that such licenses can be revoked in the event of noncompliance or fraud relating to this policy (e.g., false REC certification) and other policies.

ii. Consumer protection and education. No consumer protection efforts should be necessary with this program, but consumer education and green marketing could be fostered through REC certification and "green disclosure" requirements. Retail suppliers should be required to disclose the fraction of energy in their resource portfolio that is supported by RECs (the minimum fraction being that required by the RPS). In addition, retail sellers could be required to provide statements regarding price stability or price risks associated with their resource portfolio which would indicate the value of a higher fraction of renewable energy. This will help to reduce the transaction costs associated with green marketing that are likely to hinder these efforts, and will also assure "green" consumers that they are, in fact, purchasing renewable energy. Retail sellers should be required to file this information with the CPUC or CEC, which would then be made available to the public. Green marketers would have the option of disclosing the information directly to consumers in their bills and advertising materials. This information will also ward against the possibility of consumers unwittingly purchasing "green electricity" that only subsidizes other consumers in meeting the standard, i.e., marketers that advertise themselves as exceeding the standard, but who sell the RECs associated with that excess, thereby not increasing overall green power.

f.9 How, if at all, does the proposal relate to RD&D programs funded by the Public Goods Charge?

This proposal recommends that RD&D programs be expanded in scope and funding to cover the commercialization of technologies that are beyond the RD&D stage, but that are not yet cost-competitive with other renewables yet have significant potential for cost declines (e.g., photovoltaics). Also see question a.4.

f.10 How, if at all, does the proposal relate to energy efficiency programs funded by the Public Goods Charge?

This proposal recommends that DSM programs recognize customer-side renewable energy applications as DSM measures. In addition, this proposal recommends that energy efficiency funds be expanded to cover the commercialization of demand-side renewables, such as solar thermal hot water systems and rooftop self-generation PV systems.

f.11 How does this proposal affect the CEQA compliance work recently initiated by the CPUC?

The CEQA review should consider a scenario which does not include the RPS policy, so that the environmental impacts of potentially reduced renewables production can be measured. In addition, the positive environmental impacts associated with different levels of an RPS should be examined. See also response to question a.15.

g. Legislative Requirements

g.1 Can the CPUC implement this proposal by itself, or is legislation required? What is the status of entities not under CPUC jurisdiction in this program? What would the legislative requirement be?

See answer to b.1 above.

g.2 What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the CPUC's 1998 implementation goal?

The CPUC's 1998 implementation goal must be moved up to January 1997 given the vulnerability of many existing renewable energy projects, and thus the diversity of the state's electricity portfolio. Ideally, enabling legislation would be adopted in this legislative session, so that statewide implementation can begin by January 1, 1997. However, the CPUC must be prepared to implement this program beginning 1-1-97 if the legislature and governor do not act by the summer of 1996. Given the thought that has gone into this program, as reflected in this proposed strategy, it should be possible to have the program in place by January 1997. The CPUC need only flesh out the above items, which should be relatively straight-forward.

4. Positions of the Parties in Favor/Neutral/Oppose

Comments of the CPUC's Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

DRA/UCAN/IPP conditionally support this proposal because it includes cost certainty provisions and because credits do not accrue to distributed renewables owned by UDCs or affiliates. DRA/UCAN/IPP's condition for supporting this proposal is that it include the following:

1. RECs for post-fixed-price QFs do not become tradable until the contract is bought out.

Comments of AWEA, CBEA, GEA, STEA on their Own Proposal

SUPPORT. This proposal meets all of the Commission's policy criteria related to renewable energy and diversity. It will preserve the most efficient 80% to 90% of the existing renewables industry, relying on intra-renewable competition to keep costs low as possible. Governmental supervision is limited to checking simple reports which verify compliance with the RPS. The marketable credit system proposed has been proven in both the Federal CAA and SCAQMD RECLAIM programs. Virtually all implementation details are left to the free market in meeting the basic purchase requirement criterion. If supported by legislation, no entity is placed at a market disadvantage.

Comments of Some Surcharge/Production Credit Proposers

(Note: Where Surcharge/Production Credit Proposal supporters' names appear independently in these "Position of Parties" subsections, their position is not included in the following position statement made on behalf of the remaining supporters.)

Oppose

1. ***Ignores CPUC implementation schedule*****: *Is effective January 1, 1997.***

2. ***Fails to focus on public policy goals:*** ***This program inadequately addresses environmental improvement and new renewables technologies.***

3. Requires a complex administrative process.

4. ***Disincents QF contract restructuring:*** ***Renewables, immune from market pressure, will maintain current contracts.***

Comments of Orange County, Sonoma County, the City of Sacramento, NEO Corporation

We oppose this proposal because it gives a subsidy to existing facilities that are already favored with Standard Offer Contracts. When developers built the plants, they evaluated the risks and rewards. Ratepayers should not be forced to continue subsidizing them. These facilities are free to seek other financial support such as grants, tax credits and vendor participation. This proposal is a BRPU selection process. We vigorously oppose tiers or set asides for technologies. Competition should be market driven through an unencumbered bid process.

Comments of Los Angeles Department of Water and Power (LADWP)

Procurement of renewable resources should be the responsibility of some state entity for the state power pool and the above-market costs of compliance should be borne uniformly by all customers served by the UDC on a non-bypassable basis. Rather than having many entities responsible for procurement of renewables, having one entity responsible for the state's procurement of renewables will minimize the compliance transaction costs. The level and diversity of renewable resource mix should be established by the legislature which would determine the appropriateness of establishing set asides for certain renewable resources. The renewables program should be reviewed every five years.

Comments of Southern California Edison

This proposal allows both existing and new projects to compete to meet the purchase requirement, thereby reducing the costs of renewable development. The proposal also includes price caps, thereby placing an upper bound on the costs of the proposal. Both of these provisions are positive features.

This proposal assigns the value of renewable energy credits from existing projects under existing contracts to the project developer, not the ratepayers, and provides separate standard for biomass projects. Both of these provisions raise the costs of renewable development. The biomass provisions make administration more difficult and subsidize forestry and agricultural interests.

Comments of CalSEIA/SEIA/ETDD

SUPPORT WITH MODIFICATIONS
Diversity and New Resources: By sizing portfolio below renewables generation peak and requiring all technologies, except solid fuel biomass, to compete based solely on price, proposal ensures that existing renewables are heavily favored. Thus, proposal will not increase diversity or enable new technologies to become commercialized. Will only maintain the status quo. Requires additional bands, as with biomass, for emerging technologies not currently able to compete with existing wind and geothermal plants (see CALSEIA proposal).
Credit Price Cap: Imbalance between RECs supply and demand could cause credit prices to escalate. Reasonable caps for RECs and BECs could be imposed (see CALSEIA proposal). Relatively few buyers and sellers of RECs make imperfect market. Greater degree of extemal control to provide orderly market is likely result.

Comments of the California Integrated Waste Management Board

Support: This proposal seeks to preserve most of the 1993 level of renewable generation in California. It allows for some growth in renewable generation. It recognizes the unique environmental benefits of biomass through a separate band.

Because available renewable generation will exceed the purchase requirement, bidders will have an economic incentive to reduce costs to secure coverage under the standard. This will reduce the gap between the PX and renewables prices. The long-term result will be price competition between all generators.

The cost cap and the non-compliance penalty mechanisms are designed to assure compliance.

Comments of Don Augenstein

The "Renewables Portfolio Standard" proposal by AWEA et. al. involving RECs appears well thought-out. Its prescribed approach should result in a high degree of competition as desired by the CPUC. I believe the banding of solid fueled biomass facilities for their environmental benefits is a good idea. To the extent I have considered implications to this point, it's very good.

Comments of SoCAL Gas

OPPOSE - They propose a renewables energy target based on 96% of the 1993 percent of the state's renewable energy (10.4%), excluding hydro. This translates into a target of 10% that is expected to grow by 0.2% per year until the percentage increases by an additional 300 MW to match the level set forth in D. 92-04-045. Without respect to cost, the proposal wants to implement the anticipated results of the BRPU process. The punitive 6 cents per kWh for noncompliance is not justified. The program lacks any sunset provisions. The program seeks to grow a renewables portfolio without respect to cost.

Comments of SDG&E

Oppose:

- Proponents contemplate costs exceeding $500 million annually statewide. Proposed penalty could increase total cost to $1.5 billion
- Primarily subsidizes already-subsidized existing projects instead of new development.
- Unequal cost burden on consumers. Penalizes SDG&E's customers for not having previously been subjected to more high-priced ISO4s.
- Inconsistent with electric restructuring; mandates distribution companies to maintain resource portfolio instead of relying on the competitive market.
- High cost penalty structure proposed to force compliance rather than fostering cooperative/voluntary compliance.
- Administratively burdensome and complex process to facilitate purchase/sale of RECs at above market costs. System could be gamed.

Comments of IEP

- Requires legislation to fully implement.
- Increases regulatory burden (and costs) for non-utility retail providers including self-geneators (e.g. schools, hospitals, governmental entities, business entities) and supply aggregators.
- Places UDC's owning renewables (either via contact or through ownership) in a competitive advantage (i.e. monopsony position) vis-a-vie other, smaller retail providers seeking to enter the market for generation services.
- Policing and enforcement mechanisms to ensure compliance are unclear; relies on unnamed state agency and may require formation of new state agency.

Represents a reduction in level of renewables attained through existing state policy.

Comments of the Union of Concerned Scientists

Support.
Pros: Increment in MRPR in line with policy goals of BRPU for adding resource diversification. Exclusion of hydro avoids subsidization of a mature, fully commercialized technology and problems with annual variability. Significant 6 cents/kWh non-compliance penalty encourages compliance, does not create significant penalty fund for administration. Biomass band ensures a

diversity of renewables and values unique environmental and social attributes. Broad renewables industry support. Consumer disclosure mitigates problem of green marketers that double-dip by collecting RECs and charging more for energy. Recommends funding for emerging technologies commercialization through public goods charge.

Comments of the California Water Environment Association

1. RECs should be applied to energy and electricity generated from renewable sources and used onsite.

Reason: If cost for energy generated and used onsite is not competitive with market, a strong economic incentive to shut down this renewable energy and replace it with fossil fuel based energy may occur.

2. Add statement to exclude CTCs from electricity generated from renewables and used onsite.

Reason: The owner of above facility made a large investment in facility. The CTC recovers funds for power companies invested facilities. The CTC could prevent the renewables owner from recovering investment or being competitive.

Comments of PG&E

PG&E believes that all the RPS proposals may be basically incompatible with the increasingly competitive generation market. As the traditional, portfolio-oriented ownership and contract responsibilities slip away from utilities, and all retail suppliers rely increasingly on the spot market, the original sources of generation become more difficult to trace.

Additionally, we have three particular concerns with this proposal. The penalties are too large. The biomass set-aside is an arbitrary complication. Finally, the ratepayers should have the benefit of RECs until the end of each QF contract.

B. "Customer Choice" Renewable Portfolio Standard (RPS)

Submitted by: Independent Energy Producers Association (IEP)

1. Interpretation of Commission's Goals and Rational for Strategy

IEP recognizes and applauds the Commission's strong stand on a market-based approach to developing and fostering renewable resources. As a result of the Commission's Restructuring Decision, dated December 20, 1995 (D. 95-12-063, as revised January 10, 1996), IEP interprets the Commission's renewable policy in the context of restructuring to adhere to the following principles:

- **Maintain Existing Resource Diversity and Foster the Development of New Renewable Resources**. The Commission has stated clearly its goal of "establishing restructuring policies which maintain California's resource diversity for existing resources as well as encourage development of new resources" (D. 95-12-063, p. 146).

- **Foster Market-based Approaches in which Buyers and Sellers Exercise Choice.** The Commission notes that its "market-based" approach will allow buyers and sellers to search the market for the best renewable bargains and to internalize such costs in their prices without the need for a surcharge to fund renewables development (ibid, p. 150).

- **Investigate Need For Transitional Strategy Affecting the Resource Portfolios of Some California Utilities.** The Commission recognized that it may be appropriate to develop a transitional strategy given the current resource portfolios of some utilities, while preferring that the requirement be set at the same level for all electric utilities on a statewide basis, [ibid, p. 149]. The Commission expects that the minimum renewables levels would be in place beginning 1998 and continuing through 2000, at which point the Commission would revisit whether the requirement should be modified (ibid, p. 150).

- **Utilize Market Mechanisms and Strategies To Foster Competition in Renewable Resources.** The Commission recognized that tradeable, renewable "credits" could/would be available to provide the most flexibility in meeting the renewable standard. The Commission has reiterated its belief that a minimum renewables purchase requirement is the best approach to meet our California's resource diversity goals (ibid, p. 149).

In addition to the goals outlined in the Commission's Restructuring Decision, the Commission raised in its "Procedural Roadmap," dated March 13, 1996 (p. 27-28) the need to determine the answers to certain key questions, including the following:

- **What is the appropriate level for the minimum renewables purchase requirement?** The Commission believes that it may be appropriate to establish floors for certain technology types, in order to maintain the diversity of renewable resources (ibid., p. 150); however, the Commission seeks recommendations from parties as to such technology bands.

- **On whom the obligation should be placed?** The Commission indicated its belief that diversity goals can be achieved by placing the requirement on either retail providers of electricity, or on generators (ibid, p. 149), yet the Commission has yet to determine on whom the obligation should be placed.

- **What should constitute a meaningful penalty for non-compliance?** The Commission notes that a meaningful penalty for noncompliance should be established, but leaves open the question as to whether the "penalty" ought to be punitive (e.g. a state administered "fine") or in the nature of incentives (e.g. financial rewards for achieving a statewide renewable standard in a timely and efficient manner).

- **Is it appropriate to establish a uniform requirement for all electric providers, including utilities on a statewide basis?** It is laudable that the Commission would seek to impose a uniform requirement for all electric utilities on a statewide basis. However, the Commission's jurisdictional authority does not extent to that extent. Accordingly, the Commission must address that which it can accomplish, namely a uniform requirement on those entities subject to its jurisdiction.

The Procedural Roadmap makes clear that the Commission is seeking advice on these key issues as it moves forward in developing and implementing its renewable policy in light of industry restructuring and the creation of increasingly market-based energy markets. IEP has developed a proposal for a statewide renewable policy that addresses each of the goals and questions of the Commission in this matter.

2. Program Overview and Description

a. Origin of the Strategy

IEP has long advocated resource diversity in electric resource procurement. This position is firmly grounded in rational resource planning and consistent with California law. As part of the

California restructuring effort IEP has endorsed a "customer-choice" market-based Renewable Portfolio Standard (RPS) to provide a viable market for renewables.

The Commission's Restructuring Decision presents the first meaningful opportunity for the exercise of this customer choice. As the regulatory paradigm shifts from economic regulation of monopolies to competitive markets, captive ratepayers will be transformed into **customers** with market options. Renewable energy is a **product** that many customers favor. Therefore, customer choice must be the foundation upon which renewable energy is integrated into any sustainable future market.

To assure attainment of state policy goals in the event of market failure, IEP's proposal provides a "regulatory backstop," namely the UDC under the jurisdiction of the CPUC.

b. IEP Customer-Choice RPS Principles

IEP's Customer-Choice RPS approach is premised on the following principles:

- **Encouraging Market-forces Rather than Regulation.** IEP's proposal maximizes customer choice and market-based solutions, minimizes regulatory intervention and oversight, and ensures that the overall, statewide RPS standard is attained.

- **Administrative Ease**. IEP's proposal relies on existing institutional/regulatory structures and avoids the need to create new regulatory and administrative processes or institutions.

- **Limiting Potential Jurisdictional Conflicts**. IEP's proposal can be implemented by the Commission itself, and does not require the cooperation of other state or federal agencies. Further, because the proposal falls solely within the jurisdiction of the Commission, the proposals avoids FERC and U.S. Constitution concerns (i.e. commerce clause).

- **Political Viability and Practicality.** IEP's fundamental goal is ensuring that any renewable program (whether RPS or otherwise) results in actual kWh production. IEP's proposal does not require legislation to implement, and under the approach the UDC is financially motivated (via a PBR proceeding) to provide the regulatory backstop role to ensure timely and efficient attainment with the RPS. IEP's proposal avoids attempts to impose new mandates and enforcement/policing mechanisms on market participants not already subject to such regulatory oversight.[8]

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[8] As alluded to in the Commission's Restructuring Decision, the Commission is considering whether or not to impose a minimum renewable purchase requirement on all retail sellers or generators. Once restructuring is fully implemented with full direct access opportunities, entities potentially subject to the "all retail sellers or generators"

c. RPS Implementation

Under IEP's customer-choice RPS approach, market participants (including UDCs, supply aggregators, demand aggregators, power marketers/brokers, and bilateral contractors) will have maximum flexibility in developing renewable energy portfolios to match customer demands. To provide customers with the assurance that their renewable purchases actually derive from renewable facilities, renewable providers would be certified as "green marketers" [a elaboration of the green marketers concept is provided below]. Opportunities to purchase renewable energy/RECs would be facilitated through bilateral contracts and/or the purchase of RECs via the market.

To monitor the level of market-based compliance, all renewable "certifications" (e.g. contractual commitments) would be forwarded to the local UDC, acting on behalf of the state, for verification and compilation. The UDC will rely on these certifications as the means to measure the amount of renewable purchases in the market, and then compare the amount with the RPS. If the amount of renewables purchased in the market exceeds the RPS, no further action by the UDC is required. If the amount is less than the RPS, then the UDC enters the market (within a three month period) and purchases the requisite renewables to ensure attainment of the state's policy goals.9

Under IEP's RPS approach, each regulated public utility in the State of California would be required to assure that a minimum percentage of renewables (kWh as a percentage of total annual sales) within its distribution service territory are equivalent to that which existed for the utility as of December 31, 1993, plus that which would have existed had Preliminary BRPU winners executed contracts; further, each regulated public utility should assure to the extent practical the diversity of renewable resources within that same service territory at that time, including a solid-fuel biomass technology band. This level of renewables corresponds to approximately 13% of California's statewide energy resource mix. This level represents a reasonable starting point based on extensive analysis in the Electricity Report 1994 and the BRPU.10

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approach may include small cogenerators selling "across-the-street" (e.g. schools, hospitals, and government facilities), power marketers, retail aggregators purchasing/selling at retail to customers, and small generators selling "inside the fence."

9IEP welcomes participation by California's municipal utility districts in this program, but recognize that these entities are not subject to the jurisdiction of the CPUC. However, IEP believes that its customer-choice RPS approach is equally applicable to municipal utilities assuming that legislation were approved mandating municipal utility participation.

10IEP recognizes that, in spite of existing state law and the Commission's policies fostering renewable resource development, regulated California utilities varied greatly in the amount of renewables in their energy portfolio as of December 31, 1993. In implementing IEP's program, the Commission should endeavor to transition the level of renewables that existed for each utility as of December 31, 1993, to a state-wide standard (as a percentage

The definition of renewable energy used herein is that prescribed in existing state law (Public Utilities Code, Section 701.1), including wind, solar, biomass (including landfill gas and waste-to-energy), and geothermal energy.

Due to the non-bypassable nature of the program, all customers under the regulatory jurisdiction of the CPUC, including direct access customers, will share equitably in the costs of meeting the state's policy goals. However, the direct access customer has the choice (1) of self procurement (through such mechanisms as a bilateral contract with renewable generator(s), through the production credit market, or via an aggregator), or (2) of paying the UDC for procuring the requisite renewables on the customers behalf. If the direct access customer chooses to self procure it will have to provide verification/certification to the UDC. Upon receipt of the requisite verification/certification, the UDC will subtract an equivalent amount of renewables from its own purchasing plans. In the event that a direct access customer certifies to the UDC that a specified amount of renewables will be procured and subsequently fails to verify this, then the UDC will charge the direct access customer through the distribution bill for those renewables procured by the UDC. Under this approach, the UDC and its customers will not bear any additional cost for renewables, but society will be assured of achieving the requisite level of renewables.

d. Features To Enhance Renewable Energy Market

d.i. Renewable TradeMark

IEP believes that a renewable trademark to market "*Green Power*" will help provide consumers with additional assurance that the retail marketer selling renewables has been certified to do so. The concept behind a renewable trademark is similar to a "green seal" or an "organic" signature on products sold to consumers; each trademark provides the consumer with assurance that the product is warranted as attaining a certain product standard.

Presently, an environmental rating agency known as Eco-Rating International (ERI) provides a blueprint for the type of agency that could certify renewable energy as meeting state standards. ERI, founded in 1992 following the Rio Summit, is an environmental rating agency, and its function is to assess a project or company's environmental standing by taking reference to the most stringent international standards. ERI utilizes an evaluation instrument known as the

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of total energy sales) that would apply comparably to all entities subject to the Commission's jurisdiction, thereby making each utility more equivalent in terms of their commitment to meeting state and Commission renewable policy objectives. One mechanism to accomplish this goal would be to apportion the purchase requirement for new renewables required to attain the RPS (i.e. an amount equivalent to the BRPU preliminary winners) among the regulated California utilities in such a manner as to ensure greater comparability and equivalency among all Commission regulated entities.

"Eco-Rating" (trademark) which is applied in a manner similar to financial rating instruments utilized by Moody's Investors and Standard and Poors. The extent to which a company is deemed "green" is reflected in a numerical rating system and a color-coded scheme (i.e. shades of green).

The renewable trademark program would provide valuable benefits to both renewable retailers and consumers in terms of product definition, quality assurance, and consumer protections.

d.ii. Renewable Energy Credit(s)

A system of Renewable Energy Credits (RECs) will be developed to foster a secondary market in renewables. These credits will be created by the production of renewable energy (kWh).

RECs will be allocated to renewable generators, and they will be tradeable. However, RECs associated with existing QF generators continuing in the fixed energy price period of their contracts will accrue to the UDC and their market value will be applied to reduce the CTC associated with QF contracts. RECs associated with existing QF contracts in the SRAC period of their contracts will accrue to the QF.

d.iii. UDC As Regulatory Backstop

Irrespective of a renewables program, all customers, including direct access customers, will continue to receive a monthly bill from the UDC for distribution related charges, a public benefits charge, and a CTC. Thus, the UDC will continue to have an accounting, reporting, and most likely metering relationship with all customers, including direct access customers. The UDC is the logical entity for passing through to all customers, including direct access customers, the costs for attaining a renewable portfolio that are not realized through self-procurement in the market. Given that the distribution function(s) will remain a monopoly function, the UDC will not incur "competitive disadvantage" resulting from this proposal, because the UDC is not "in competition" to provide its services.

d.iv. Administrative Accountability

The UDC role as "regulatory backstop" will be evaluated as part of the UDC's non-generation PBR proceeding. The UDC PBR mechanism will include incentive mechanisms fostering the timely and least-cost acquisition of renewables to ensure attainment of the RPS. The UDC will be financially rewarded for obtaining renewables in a timely manner for the least cost. In addition, the UDC will be guaranteed a rate of return for all prudently incurred administrative expenses.

e. Additional Concepts Being Considered As Potential Options In A "Customer Choice" RPS Approach

IEP is investigating additional concepts and mechanisms to foster a vibrant and competitive market for renewable energy in light of industry restructuring.

e.i. CTC Credit Option

The Commission should consider a policy allowing direct access customers entering into bilateral contracts with renewable QFs to be eligible for a credit of all or a portion of the competition transition charge (CTC). Under this approach, an entity that reduces the UDC's CTC associated with QF contracts (for example, if a municipality or large consumer bought-out a biomass QF contract from the utility in order to ensure its continued operation) would receive a comparable credit for CTC costs which it would otherwise pay to the UDC. Alternatively, if a customer purchases 100 percent of its energy from a certified renewable purchaser, then that customer would be credited as having paid 100 percent of the CTC. If the customer purchases 50 percent renewables, then it would be credited as having paid 50 percent of its CTC. If, as some propose, the CTC is valued at around 4 cents kWh, this approach provides customers with a real incentive to purchase the most cost-effective renewable resources available.

e.ii. State Purchase

Renewable resources are acknowledged through existing state law (see Public Utilities Code, Section 701) and Commission policy to provide important benefits to the state and public at large, including resource diversity, economic development and jobs, and environmental benefits. In order to ensure that the public continues to realize these benefits, the state on behalf of the public should act to ensure the continued presence of renewable resources in the state's energy portfolio.

The state is a very large consumer of energy. For example, the California Department of General Services (DGS) and the California Department of Water Resources (DWR) purchase vast amount of energy to meet their own requirements. These entities represent in the aggregate some of the largest load in the state of California.

If state agencies such as DGS and DWR were required to meet a portion of their total load through the purchase of renewable technologies, then the public benefits associated with renewable energy production would be realized and paid for by the public at large (as represented through its purchasing agent the respective state agency).

3. Implementation Questions

a. What Is The Obligation?

a.1 How is "renewables generation" defined for purposes of qualifying for tradable "Renewables Energy Credits" (RECs) under this proposed program? Do existing and incremental utility-owned renewable-resource generation qualify for Renewable Energy Credits?

Renewables generation is defined on a kWh basis (i.e. energy generated). The definition of renewable energy reflects that prescribed in existing law (Public Utilities Code, Section 701.1), including wind, solar, biomass (including solid-fuel, landfill gas and waste-to-energy), and geothermal energy.

The RPS is established to reflect the level of renewables that existed as of December 31, 1993, plus what would have occurred if the Preliminary BRPU winners executed contracts. To the extent that the RPS includes existing utility-owned renewables, then the RPS percentage would be adjusted accordingly.

a.2 What are renewable energy credits? How do they relate to energy portfolio management?

Renewable energy credits (RECs) represent a unit of energy production (one credit per kWh of production). RECs may be used to supplement and/or supplant bilateral contracts to ensure that parties attain their renewable portfolio.

a.3 How is a diversity of renewables encouraged?

Under IEP's RPS approach, each regulated public utility in the State of California would be required to assure that a minimum percentage of renewables (kWh as a percentage of total annual sales) within its distribution service territory are equivalent to that which existed for the utility as of December 31, 1993, plus that which would have existed had Preliminary BRPU winners executed contracts; further, each regulated public utility should assure to the extent practical the diversity of renewable resources within that same service territory at that time, including a solid-fuel biomass technology band. To the extent that the amount of renewables required under the RPS exceeds that which existed as of January 1, 1994 (e.g. due to load growth), then all renewable technologies would be expected to compete to serve the additional demand.

a.4 Are currently high-cost technologies or pre-commercial technologies fostered by this program?

IEP's RPS proposal fosters certain high-cost renewable technologies that have proven to be commercially/operationally viable, specifically solid-fuel biomass. While encouraging the diversity that existed as of January 1, 1994, IEP's approach maximizes competition among all the diverse technologies to meet demand. To the extent that certain technologies are "pre-commercial," IEP would support their continued development and operation outside the RPS standard as part of a public goods charge.

a.5 How is renewable self-generation handled? Is self-generated renewable energy eligible for Renewable Energy Credits (RECs), or for other means of support?

Renewable self-generation would be treated as equivalent to a "bilateral," direct access arrangement (wherein the buyer and seller are the same entity). Under this arrangement, the self-generator would (1) avoid a commensurate UDC renewable charge and (2) own any RECs associated with the production of the renewable energy.

a.6 How are hybrid fossil-fuel/renewable facilities handled?

If a facility is certified as a "green seller," then the production from that unit is deemed renewable for purposes of the RPS and the RECs. The eligibility criteria for designation as a green seller are yet to be developed, and would be expected to allow for a limited amount of fossil-based generation to provide for operational constraints (e.g. start-up). Presently, some renewable QFs are allowed up to 25% of their fuel to be fossil-based in order to provide for operational constraints.

a.7 Does out-of-state generation qualify for Renewable Energy Credits (RECs)? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

IEP's definition of renewables is that prescribed in existing state law (Public Utility Code Section 701.1) which does not distinguish between in-state and out-of-state generation. As a practical matter, a program that defines renewables and then provides exclusions for out-of-state generation may not satisfy the Commerce Clause of the U.S. Constitution.

a.8 If hydro is included, how are practical issues associated with hydropower handled?

Public Utilities Code Section 701.1 explicitly identifies renewables such as wind, solar, biomass, and geothermal energy. IEP does not contemplate that hydro-based generation would be included in the RPS.11

a.9 How is utility-owned generation of distributed renewables handled? Does the proposal permit or prohibit Renewable Energy Credits from being awarded to distributed utility-owned renewable power not sold through the Power Exchange? Does the proposal permit Renewable Energy Credits to accrue to applications that may involve the cross-subsidization of generation with T&D savings, or vice versa?

The proposal does not explicitly address utility owned-distributed generation.

The UDC's Performance Based Ratemaking (PBR) mechanism would be adapted to address concerns such as self-dealing and cross-subsidization between utility functions as regards renewables. UDCs should be precluded from entering into bilateral contracts with affiliated entities.

a.10 What is the level for the requirement? How does this level relate to the level of renewables from 1990 to the present? Does the level of the requirement increase over time, and, if so, at what rate?

11If hydropower were included in the RPS approach, the RPS (i.e. the percentage level) would have to be increased to reflect this fact. Further, the RPS would have to be adapted to address, among other matters, the competitive advantages inherent in large, federally subsidized hydropower facilities.

Under IEP's RPS approach, each regulated public utility in the State of California would be required to assure that a minimum percentage of renewables (kWh as a percentage of total annual sales) within its distribution service territory are equivalent to that which existed for the utility as of December 31, 1993, plus that which would have existed had Preliminary BRPU winners executed contracts[12]; further, each regulated public utility should assure to the extent practical the diversity of renewable resources within that same service territory at that time, including a solid-fuel biomass technology band. The RPS does not increase over time.

a.11 Describe how, if at all, the compliance obligation adjusts during the transition period.

The compliance obligation does not adjust during the transition period.

a.12 Does the proposal include a uniform requirement for all electric providers, on a statewide basis?

The proposal relies on market opportunities and maximum customer choice to attain the RPS. All California UDCs subject to the jurisdiction of the Commission will be subject to the uniform requirement, thereby providing the regulatory "backstop" to fill-the-gap between market effects and the RPS. The UDC "requirement" will vary on an annual basis depending on the success to which renewable energy is able to garner market share. However, UDC costs, if any, associated with fulfilling the requirement will be recovered from all customers/end-users of the transmission distribution system (excepting direct access customers choosing to self-procure renewables).

IEP welcomes participation by California's municipal utility districts in this program, but recognize that these entities are not subject to the jurisdiction of the CPUC. However, IEP believes that its customer-choice RPS approach is equally applicable to municipal utilities assuming that legislation were approved mandating municipal utility participation.

a.13 What is the time-horizon for the program?

The RPS program should begin as soon as possible, but no later than January 1, 1998. In light of the state's existing statutory commitments to resource diversity and renewable resources which are expected to persist, the specific RPS program to help attain the statewide goals and objectives should continue at a minimum until such time as a fully competitive market has emerged characterized by full direct access, many buyers and sellers, etc.

a.14 Is the requirement established on a percentage of megawatts or percentage of megawatt-hours basis?

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12 IEP estimates the level of energy expected from BRPU preliminary winners to total 5,499 Gwh (assumes 90.4% capacity factor for biomass and geothermal and 25% capacity factor for wind and hydro).

Percentage of megawatt-hours basis (i.e. energy and not capacity).

a.15 Does the proposal establish floors for certain technology types? What is the rational for a technology floor, if proposed?

The proposal seeks to ensure the level of diversity (kWhs) that existed as of December 31, 1993. The proposal provides a technology floor for solid-fuel biomass in recognition of specific non-energy related public benefits derived from its operation. Above and beyond this amount, renewables would compete to meet demand.

b. Where Is The Obligation To Comply?

b.1 On whom is the requirement applied? Is the requirement applied only to entities under the Commission's jurisdiction, or is it applied statewide?

The regulatory mandate related to the RPS would be imposed on the regulated utility distribution companies (UDCs) which are within the jurisdiction of the Commission. Entities not under the Commission's jurisdiction are not subject to the regulatory requirements. However, this proposal is designed to foster to the maximum extent possible the voluntary participation of market participants through the market-based mechanism structured around the principle of "customer choice."

IEP welcomes participation by California's municipal utility districts in this program, but recognize that these entities are not subject to the jurisdiction of the CPUC. However, IEP believes that its customer-choice RPS approach is equally applicable to municipal utilities assuming that legislation were approved mandating municipal utility participation.

b.2 Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences?

Entities not under the Commission's jurisdiction are not subject to the regulatory requirements. However, this proposal is designed to foster, to the maximum extent possible, the voluntary participation of market participants, via a market-based mechanism structured around the principle of "customer choice." The regulatory requirements are imposed on those entities subject to the regulatory jurisdiction of the Commission. The costs associated with implementing the program will be reflected in a distribution surcharge, all distribution customers (whether served by regulated or unregulated retail providers) will participate in funding the program on a non-bypassable basis. Customers can control these costs by self-procuring renewable resources through the direct access market.

b.3 What is the penalty for non-compliance? Should this penalty be interpreted as a cost-cap for the program?

The primary incentive to attain the RPS is market-based. However, to the extent that a sufficient "green market" fails to materialize, the program is designed to financially motivate the UDCs (e.g. via a PBR mechanism) to procure in a timely and efficient manner the requisite renewable energy to attain the RPS. To the extent that the UDCs are ineffective in meeting this obligation, they would not realize the financial rewards of doing so.

b.4 How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

On an annual basis, the Commission will review the performance of each UDC as regards attainment of the RPS. The UDC will receive from each of its direct access customers self-procuring renewables a certification (e.g. portions of contract language) that makes clear the direct access customer contracted for an amount of renewables. The UDCs will sum these certifications and determine the remaining amount of renewables required to attain the RPS. The UDC will be provided a 3-month "true-up" period to enter the market to procure a sufficient amount of renewables to ensure attainment of the standard. The Commission will determine as part of the UDCs PBR proceeding whether compliance has been accomplished and address any disputes that may arise.

b.5 What provisions add flexibility to compliance, if any?

The Commission will provide monitoring and oversight. The UDCs PBR proceeding provide the vehicle to ensure compliance in a timely and efficient manner. To maximize the flexibility of the UDC to serve its function as regulatory backstop, the UDC will have a true-up period in which to acquire renewables through the REC market.

b.6 How does the program ensure that the policy and its costs are non-bypassable, such as the CTC or the Public Goods surcharge?

Costs borne by the UDC are passed through to **all** distribution customers, including direct access customers (except direct access customers certifying self-procurement), as part of a distribution-based surcharge. This ensures that the costs for the renewable program are borne by all customers on a non-bypassable basis.

c. How Are Renewable Energy Credits Initially Allocated?

c.1 How are Renewable Energy Credits (RECs) generated from existing renewable facilities (QFs and utility-owned) initially allocated? What impact does the initial allocation have on whether a vigorous market for RECs, characterized by many buyers and sellers, forms?

RECs associated with utility-owned renewables accrue to the utility. The RECs associated with QFs continuing in their fixed price energy payment period also accrue to the utility and their value is used to reduce any CTC associated with QF projects. The RECs associated with QFs not in their fixed price energy payment period, but rather SRAC payments for energy, accrue to the QF. In all other instances, RECs are allocated based on the contractual arrangements entered into by bilateral parties.

c.2 What is the relationship of the allocation of renewable energy credits and the CTC or Public Goods surcharge? Will RECs accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid and avoid the CTC?

To the extent the UDC derives value from RECs associated with existing contracts or existing plant facilities receiving CTC treatment, any value/benefit associated with the RECs should pass-through to the ratepayers by reducing the associated CTC.

IEP is investigating the feasibility of creating additional market-based incentives to foster renewables and ensure attainment of the RPS, thereby further relieving the UDC of its obligation to purchase renewables. Under investigation is the potential for direct access customers who serve their load from renewables to realize a credit against any CTC obligation equal to the CTC reduction achieved.

c.3 If customers or ratepayers are initially allocated RECs, how are the credits administered?

RECs are a tool to facilitate a market in renewable energy and help evidence attainment of the RPS. One credit is associated with one kWh of renewable production. Credits (and the verification thereof) are administered by the UDC under the direction of the CPUC as prescribed by law or policy.

c.4 How would the proposed Renewable Energy Credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make them more or less cost effective to rate payers?

The extent to which the allocation of RECs will affect negotiations to buyout existing QF contracts will be a function of the economic value associated with the RECs. This value remains unknown at this time.

c.5 How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

[see answer to c.4]

c.6 Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

If the renewable market is sufficiently vibrant, then the UDC's renewable purchase obligation will diminish. This may result in the utility-owned renewables having less value under the ownership of the UDC, but more value under the ownership of an unaffiliated market-player interested in direct access market opportunities. This may encourage divestiture of certain renewable assets. The ratepayer should be indifferent, having received market value for the divested asset (plus CTC as appropriate).

d. How Is The Program Administered?

d.1 What agency certifies the Renewable Energy Credits?

The CPUC can be the entity certifying the RECs, although another state agency could easily accomplish this fact.

d.2 What mechanisms are proposed for trading of Renewable Energy Credits? How do the trading mechanisms relate to the initial allocation of Renewable Energy Credits?

To the extent that IEP understands the trading mechanisms proposed by other parties, IEP's proposed trading mechanisms is no different.

d.3 What mechanisms are proposed for program oversight and mid-course corrections?

The Commission will provide monitoring and oversight. The UDCs PBR mechanism provide the vehicle to ensure compliance in a timely and efficient manner.

d.4 What agency monitors and enforces compliance with the program, and how is it carried out?

The Commission will provide monitoring and oversight. The UDCs PBR mechanism provide the vehicle to ensure compliance in a timely and efficient manner.

e. Cost-Related Issues

e.1 What are the costs associated with the program, and who pays?

The costs of the program are dependent on the success of the bilateral market for renewable energy. If the bilateral renewable market is successful, then the cost to UDC ratepayers is zero. To the extent that any UDC costs arise, then all the UDCs distribution customers participate in funding the program through a non-bypassable public goods charge.

e.2 What cost-containment measures, if any, are provided?

The rigors of the competitive market are the primary forces for containing costs. Retail "green marketers" will compete to lower the portfolio costs associated with renewable energy while meeting the demands of the customers exercising choice in the marketplace.

e.3 If the program utilizes floors for certain technology-types, what are the cost implications?

IEP's proposal prescribes only a signal technology band for solid-fuel biomass. This minimizes the costs associated with a technology band approach, and ensures that competition for renewables is as broad as possible. This approach is expected to minimize the total cost for the program while providing a mechanism to ensure maintenance of the existing level of benefits derived from renewable technologies including solid-fuel biomass.

e.4 Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

The implementation of a public goods charge pursuant to the RPS approach should not result in any cost-shifting among consumer groups. Regarding the issue of cost-shifting between regions, implementation of the program will help attain the policy goals established by the state legislature during the 1980s by ensuring that utilities which failed to meet their renewable resource obligation do so in a timely and efficient manner. Cost shifting does not materialize when UDCs are motivated to accomplish policy goals previously enunciated by the state legislature and the Commission.

e.5 How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities?

IEP's proposal fosters competition among all the renewable technologies to "capture" that portion of the renewable supply that exceeds that which existed as of December 31, 1993. In addition, to the extent that load-growth occurs in jurisdictions under the CPUC authority, then the size of the renewables will increase concomitantly, and all renewable technologies will compete to meet this additional demand.

e.6 What implications, if any, does the proposal have in defining the roles of the UDC and of competitive suppliers of electricity?

Assuming the UDC is functionally unbundled (as directed by the Commission) from the utilities transmission and generation functions, yet the distribution services remain regulated monopoly functions, then the UDC should be financially indifferent to the direct and/or indirect effect that any renewable program has on the competitive position of individual generators. Because the RPS surcharge is non-bypassable and will be charged to all direct access customers (excepting those choosing to self-procure renewables), then the RPS surcharge does not impose any competitive disadvantage on the UDC vis-a-vis the retail distribution business. However, if the UDC is not competitive in its procurement of renewables to attain the RPS standard, then the risk remains that direct access customers will procure such renewables from other direct access retailers.

e.7 What is the consistency of this proposal in relation to cost-related guidance provided by the PUC Roadmap?

IEP believes that its approach conforms to the Commission's cost concerns, by minimizing administrative and procurement costs while maximizing the diversity benefits derived by sustaining as diverse a portfolio as practical via the marketplace.

f. How Does The Program Fit With Other Aspects Of Electric Industry Reform?

f.1 Is the program compatible with the existence of an Independent System Operator? A Power Exchange? A Direct Access Market? Is the proposal consistent with the Commission's vision of the role of the Power Exchange and ISO?

Nothing in the IEP proposal is incompatible with the Commission's vision of the role of the ISO and the Power Exchange in a restructured market.

f.2 Is the proposal dependent in any way on the Power Exchange or ISO? If so, are any additional protocols necessary?

No.

f.3 Does the proposal involve conflicts of interest between distribution and competitive retail service? If so how are they resolved?

Implementation of the renewable RPS is separate from the competitive market for non-renewable energy. Accordingly, the competition between the UDC and direct access providers will not be affected by implementation of the standard. All customers, including direct access customers, will be subject to the renewables public goods charge unless the direct access customers choose to procure such resources on their own. Furthermore, assuming the UDC is functionally unbundled from the utilities transmission and generation functions, then the UDC should be financially indifferent to the direct and/or indirect effect that any renewable program has on the competitive position of individual generators.

f.4 How does the program avoid conflicts of jurisdiction between state and federal levels?

IEP's proposal is totally within the jurisdiction of the Commission to implement because the purchase requirement is place solely on the state-regulated utility distribution company. Accordingly, the proposal does not raise questions of FERC jurisdiction nor does it raise commerce clause concerns, because this program can be implemented by the Commission on its own action and the program does not require legislative action. No state and/or federal jurisdictional issues should arise via this proposal. This assures that the program can be implemented in a timely and efficient manner, and that it will not be delayed due to jurisdictional and legal appeals.

f.5 What is the relationship between the Proposal and Direct Access "Green Marketing"

IEP believes that a renewable trademark to market "*Green Power*" will help provide consumers with additional assurance that the retail marketer selling renewables has been certified to do so. The concept behind a renewable trademark is similar to a "green seal" or an "organic" signature on products sold to consumers; each trademark provides the consumer with assurance that the product is warranted as attaining a certain product standard.

Presently, an environmental rating agency known as Eco-Rating International (ERI) provides a blueprint for the type of agency that could certify renewable energy as meeting state standards. ERI, founded in 1992 following the Rio Summit, is an environmental rating agency, and its function is to assess a project or company's environmental standing by taking reference to the most stringent international standards. ERI utilizes an evaluation instrument known as the "Eco-Rating" (trademark) which is applied in a manner similar to financial rating instruments utilized by Moody's Investors and Standard and Poors. The extent to which a company is deemed "green" is reflected in a numerical rating system and a color-coded scheme (i.e. shades of green).

The renewable trademark program would provide valuable benefits to both renewable retailers and consumers in terms of product definition, quality assurance, and consumer protections.

f.6 What is the relationship between the proposal and Performance-Based Ratemaking (PBR)? Does the proposal place Renewable Energy Credits under PBR, or exclude Renewable Energy Credits from PBR?

A PBR mechanism will be used to provide the Commission the opportunity to measure (and police) the extent to which the UDC has procured the requisite amount of renewables in a timely and efficient manner. The PBR should be structured to provide financial incentives to the UDC to meet the state's policy goals and objectives.

f.7 Does the program create any potential market-power problems involving the generation market or Renewable Energy Credits (RECs)?

To the extent that market-based solutions are employed (i.e. creating opportunities for many buyers and sellers of RECs), then market power concerns lessen.

f.8 Does the proposal relate to any consumer protection or consumer education efforts? For example,

a. Rules for new entrants: Does the proposal entail any licensing requirements for new entrants? Should compliance with the minimum renewables requirement be a condition of selling power at the retail level?

b. Consumer education: Does the proposal require any consumer education? For example, how does the proposal protect consumers from "green marketing" programs where marketers collect twice -- once for credit sales and once for "green" power sales, thereby not increasing total green power? This could entail, e.g., disclosure requirements to inform consumers about the amount of renewable energy they are purchasing that is supported by Renewable Energy Credits, or statements regarding price stability or price risks associated with the seller's resource portfolio. Would RECs accrue to utilities from green pricing programs where utilities have unique customer information and access?

The certification of "green marketers" will have state-approved criteria to protect against consumer fraud, and provide the mechanism to prosecute entities who fail to abide by the rules governing the certification. The purpose would be to provide necessary consumer protections, disclosure, and information/access.

Because the RPS mandate applies to only to the UDC, licensing requirements on all retail providers would not necessary in order to implement the program (licensing requirements may be necessary and appropriate for other reasons). Moreover, compliance with the RPS would not be a condition for selling power at the retail level.

The "green marketing" program would be designed to provide explicit consumer protections. In addition to being warranted by the state for having certain renewable attributes, a "green seller" would be expected to provide consumers with information related to the source and type of renewable energy being sold, the amount of renewable energy in the portfolio (including the amount of RECs), and other information deemed appropriate.

f.9 How, if at all, does the Proposal relate to RD&D programs funded by the Public Goods Surcharge?

The proposal is not meant to address renewable technologies more suitable for RD&D-type programs.

f.10 How, if at all, does the Proposal relate to energy-efficiency programs funded by the Public Goods Surcharge?

This proposal has no direct relationship to energy-efficiency programs funded by the public goods surcharge. This proposal does, however, administer a surcharge mechanism in the same manner as is proposed for public goods.

f.11 How does this proposal affect the CEQA compliance work recently initiated by the Commission?

This proposal does not necessarily change the existing mix of supply resources, except to create the opportunity for the development and operation of cleaner and more efficient energy technologies.

g. Legislative Requirements

g.1 Can the Commission implement this proposal by itself, or is legislation required? What is the status of entities not under Commission jurisdiction in this program?

The Commission can implement this proposal by itself. Entities not under the Commission's jurisdiction are not subject to the regulatory requirements.

g.2 What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the Commission's 1998 implementation goal?

This program does not require action by the legislature. Accordingly, it may be implemented as soon as the Commission is prepared to move forward. IEP would hope that this program would be implemented no later than January 1, 1998.

4. Positions of the Parties in Favor/Neutral/Oppose

Comments of the CPUC's Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

DRA/UCAN/IPP opposes this proposal because it:

1. It would monopsonize renewable generation and/or renewable energy credits in each UDC service territory, diminishing competition in renewables markets.

2. Puts UDCs in a conflict of interest by forcing them to manage REC porfolios or maintain renewable generation on behalf of competitors.

3. Requires more regulation of the wires company by the Comission, rather than less, as is desired.

4. Does not resolve municipal utilities and cooperatives being able to opt out of the renewable requirements.

Comments of AWEA

SUPPORT WITH SOME RESERVATIONS. Proposal would preserve virtually all of the existing renewables industry, includes a biomass band, and avoids problems of accomodating hydros. Also accepts as renewables plants necessarily using up to 25% fossil fuel. However, proposal places unequal burden of above-market renewable costs only on regulated UDCs, allowing market advantage to publically-owned utilities and power marketers. Having only three buyers of RECs may create oligopsony situation, with resulting inappropriate exercise of market power. Since preservation of existing renewables would be accomplished, this proposal is acceptable if AWEA et al proposal is rejected.

Comments of CBEA

Concur with AWEA. Proposal includes a biomass band, recognizing higher costs of solid fuel collection, processing, and transportation, and additional environmental benefits associated therewith. Also accepts as renewables those plants required to use up to 25% fossil fuel for startup, process stabilization, and/or flame stabilization. Although proposed program is market based, have concern that "green market" incentives will not be sufficient to accomplish compliance, relying possibly inappropriately on UDC to make up shortfalls. May place UDC in conflict of interest position in having to bill its competitors' customers for make-up RECs, requiring greater regulatory oversight.

Comments of GEA

Concur with AWEA. This proposal would support existing renewables, which we interpret as CPUC objective, as opposed to the EDF et al proposal which provides support only for new renewables. This approach might put UDCs in a conflict position by having to manage REC portfolios or maintain renewable generation for their competitors. At minimum, this potential conflict situation would require more regulatory oversight than a complete free market approach such as proposed by AWEA et al. On the other hand, this proposal could be accomplished solely by the CPUC, without legislation, a possible strong point.

Comments of STEA

Concur with AWEA. This proposal is viewed as fall-back position in event that the AWEA proposal is rejected for some reason. One concern is use of the PBR mechanism as the "enforcement" for the MRPR, as opposed to a non-compliance penalty. Charging UDCs with making up shortfalls in compliance on the part of retail electricity providers allows those providers to opt out of compliance if they choose. On the positive side, this proposal includes an RPS sufficiently large to preserve the existing renewables industry, but the "green marketing" approach may not force prices as low as competitive approach of AWEA.

Comments of Some Surcharge/Production Credit Proposers

(Note: Where Surcharge/Production Credit Proposal supporters' names appear independently in these "Position of Parties" subsections, their position is not included in the following position statement made on behalf of the remaining supporters.)

Oppose:

1. ***Fosters perverse incentives*: This proposal calls for "old world" command and control. It encourages program "gaming," adversarial conduct, and litigious atmosphere rather than pursuit of success in open competition.**

2. ***Fails to define costs*: This program has no cost cap and hence, provides no tool for analysts to calculate probable program costs prior to implementation or for UDCs to gauge program costs from one year to the next.**

3. ***Requires utilities to maintain resource portfolios in addition to pool purchases:* This requirement will be very complicated to administer and is inconsistent with the CPUC**

decision. Necessary UDC/REC contracts, likely above market and signed after 1/1/98 for required purchases, are not eligible for CTC.

Comments of Orange County, Sonoma County, City of Sacramento, NEO Corporation

We oppose this proposal because it subsidizes existing facilities. We believe all money should go to new projects with the latest technology. Private sector developers evaluated and took risk years ago when they built. Ratepayers did not share in the profits and should no longer have to support them. These facilities are free to seek other financial support such as grants, tax credits and vendor participation. This proposal is a BRPU selection process. We vigorously oppose tiers or set asides for technologies. Competition should be market driven through an unencumbered bid process.

Comments of the Union of Concerned Scientists

Oppose.
Good Points: MRPR set at 1993 levels + preliminary BRPU winners, reducing need for increments. Exclusion of hydro. Biomass band ensures a diversity or renewables and values unique environmental and social attributes. Does not require legislation.
Bad Points: Has no non-compliance penalty, outside of undefined CPUC incentive action on PBR rate cap. Not competitively neutral: obligation placed on UDC only, excluding munis from requirement. UDCs do not have as strong as an incentive as retail suppliers to find low-cost, high performing, high value projects. Green marketers would be able to double-dip by collecting RECs and charging more for energy.

Comments of Los Angeles Department of Water and Power (LADWP)

The procurement of renewable resources should be the responsibility of some state entity for the state power pool and the above-market costs of compliance should be borne uniformly by all customers served by the UDC on a non-bypassable basis. Rather than having many entities responsible for procurement of renewables, having one entity responsible for the state's procurement of renewable resources will minimize the transaction costs of compliance. The level and diversity of renewable resource mix should be established by the state legislature. The renewables program should be reviewed every five years or so.

Comments of Southern California Edison

This proposal has some of the same flaws as the AWEA et al. proposal: a separate biomass standard and allocation of credits from existing projects under existing contracts to the project developer, not the ratepayers. The proposal also includes a particularly troublesome provision that requires the local distribution company to serve as a “regulatory backstop” in the event a retail provider does not meet the requirement. This provision places an administrative burden on the local distribution utility while freeing power marketers and brokers to ignore the entire renewable requirement if they choose to do so.

Comments of CalSEIA/SEIA/CEC/ETDD

OPPOSE
Purchase Timing Exacerbates Market Instabilities: Potentially unstable and unworkable mechanism due to timing of renewables purchases by customers first with UDCs as backstop. UDCs must wait untill late in annual purchase cycle to determine amount of customer purchased RECs. Late market entry of UDCs may find insufficuent numbers of RECs available, since RECs don't exist until after power is generated. This forces renewable generators to take risk of generating without certainty of purchaser or price for RECs or to not generate and cause REC shortage. Stability of market-based approaches require most RECs be pre-sold to provide minimal revenue certainty to generators. Similary, oligopsony power of three UDCs poses problem for orderly and fair market for RECs.

Comments of the California Integrated Waste Management Board

Modified Support: The proposal contains the attractive features of a market-based RPS. As with the AWEA, et al. proposal there is a biomass band. This proposal could be implemented by the Commission without legislation.

The proposal may allow for the largest cohort of renewable energy by including the load growth that the now-defunct BRPU would have provided. Conversely, the proposal does not include all retail sellers in California.

IEP is perhaps a little optimistic about the effectiveness of emerging "green marketing." This proposal may not result in quite the level of price competition as the AWEA, et al. proposal should.

Comments of Don Augenstein

This "Customer Choice" Renewable Portfolio Standard proposal appears well thought out. A set-aside or "banding" for solid biomass fueled facilities is reasonable based on environmental justifications under the utility code (non-energy public benefits). However a proposed 13%

of renewables in the portfolio may result in some high renewables costs at the outset, inasmuch as it would be difficult to "ramp up" quickly. It needs to mention other biogas as well as landfill gas. On the whole it appears a very good proposal.

Comments of SoCAL Gas

No justification to use a 13% level as the target level (renewable energy production in January 1994 plus the equivalent energy production from the preliminary BRPU winners). Allowing customers purchasing energy from renewable QFs to avoid paying the CTC undermines the nonbypassable aspect of the CTC. If the QFs were solely responsible for all of the CTC their proposal would be fair. It also results in a further subsidy to renewables as the remaining customers would have to pay for the non renewable portion of the CTC avoided by renewable purchasers. Requiring the utilities to continue the administration of the project is not desirable, given they no longer have the mandate for energy procurement.

Comments of SDG&E

Oppose:

- No cost limitation.
- Primarily subsidizes already-subsidized existing projects instead of new development.
- Cost responsibility inequitably allocated to consumers based on illegal BRPU, which would leave had San Diego consumers pay in excess of 20% above market costs.
- Inequitable for consumers because municipal customers pay no share of IEP's proposal.
- Inconsistent with electric restructuring; mandates distribution companies to maintain resource portfolio instead of relying on the competitive market.
- A competitive renewable trading market likely will take significantly longer than two years to develop.
- Administratively burdensome and complex.

Comments of PG&E

PG&E believes that all the RPS proposals may be basically incompatible with the increasingly competitive generation market. IEP creates the opportunity for other sellers to avoid the requirement, thus imposing unknown costs on the utility. This “solution” echoes the traditional resource planning approach and may not be appropriate as all market suppliers increasingly use the short-term generation market.

C. Renewable Capacity Credit Proposal

Submitted by: Northern California Power Agency

1. Interpretation of the Commission's Goals and Rationale for Strategy

The California Public Utilities Commission indicated in its December 20, 1995 Electric Service Markets policy decision, D.95-12-063, corrected by D. 96-01-09, that protection of the state's existing investment in renewable technologies and the promotion of future development of renewables remain a continuing and important state policy. The Commission indicated that a requirement that the electric supply portfolios of jurisdictional utilities include a renewable component is consistent with its approach to electric industry restructuring, and expressed a preference for a "market-based" approach.

The over-arching goal of electric industry restructuring as asserted by the Legislature in Assembly Concurrent Resolution 143 (1994) is achieving lower rates and bills for consumers, consistent with assuring environmental quality and achieving other public policy goals including maintaining a diverse electricity generation resource mix. Requiring the state's consumers to support a substantial level of electric generation capacity relying on renewable resources within the state is consistent with that fundamental goal if the conventional understanding of renewable resources, including hydropower, is employed. Any arbitrarily limited notion of renewable resources would fail to comply with the requirements both of the Commission and the Legislature, because it would artificially limit the actual diversity of non-fossil renewable resources such portfoilos would otherwise exhibit.

The Renewable Resource Capacity Credit (RRCC) proposal satisfies all of the Commission's criteria. Under the system established by this proposal a renewable facility located in California will get a market or contract price for its energy output ***and*** an additional payment for the value of the operable renewable capacity in the form of a tradeable renewable resource capacity credit. The added rent associated with the tradeable credit will support existing facilities and attract new facilities that are of greater or equal value or are needed to track growth in peak demand.

The proposal is simple and non-discriminatory. The proposal applies equally to all retail sellers in California (and therefore all electric customers.) It treats all renewable technologies the same, while allowing for operational differences and differing levels of risk tolerance and risk aversion of the capacity owners. While it requires an intense level of analysis prior to initial establishment, once established it is extremely simple: energy is sold on a market for a market price and credits are created and traded independent of the energy sales (unless bundled pursuant to bi-lateral agreement between a generator and retailer.) This radical separation between energy markets and renewable capacity credit market permits the energy market created by restructuring to develop according to its own logic and economies, separate from the generation of additional revenue to support the policy objective of renewable resource support. It limits the extent to which energy markets are distorted by the policy objective, while supporting a revenue stream dedicated to the policy objective.

The proposal is presented in the form of draft legislation, including extensive legislative findings, because legislation will be required to

- apply a renewable portfolio requirement to all retail sellers, including public agencies and marketer/brokers;
- construct the credit, credit exchange mechanism and credit exchange procedures;
- develop the penalty mechanism.

Legislative language may supply a level of rigor of presentation and may support a level of rigor in analysis and critique that could be important in area where the details matter. The narrative description of attributes should not be a substitute for reading the actual text of the proposal.

2. Program Overview and Description

a. Narrative Presentation

The attributes of the system contained in this proposal are:

- A requirement that each retail seller of electricity in California obtain on an annual basis renewable resource capacity credits (RRCCs) equalling or exceeding 18 percent of the sum of its monthly peak loads.

  Credits for renewable capacity achieves the objective of maintaining renewables in the state's portfolio. It permits relative stability and predictability in the credits market. The 18 % number is roughly the proportion of statewide net dependable renewable capacity as per the 1994 Electricity Report of the Califorina Energy Commission. ER '94 (Table 7-1, page 94) available to meet 1998 forecasted statewide annual peak demand plus losses (Table 6-3, page 83.) Since the standard is based on average monthly rather than annual peak, it is unlikely that there will be a shortage of RRCCs.

- RRCCs are issued monthly to owners of facilities located in California using renewable resource electric generation technologies (RREGTs) that meet an operational performance requirement (the qualifying capacity factor (QCF)).

  - RREGTs include hydro but not pumped storage.
  - California location requirement assures that rents associated with credits that are paid by local California customers purchase local California benefits

- The QCF creates incentive for operating renewable facilities at average levels of efficiency, and smooths out variations in output due to seasonal operating constraints (wind, hydro, solar), extended scheduled maintenance (geothermal), forced outages, etc.

- monthly issuance lessens opportunities for gaming, speculation.

- The number of RRCCs issued to any owner is based on the owner's registration of a capacity value for a facility utilizing RREGT, up to the nameplate for the facility.

  This permits an owner to calibrate levels of risk and reward. Registration of a low number increases the probability that credits will be awarded, but reduces the number of credits. This is important for intermittents (wind and solar) and facilities with seasonal operating constraints (hydro, biogas) or proabilities of forced outages (biomass).

- The QCF is calculated as the ratio of energy output to the registered capacity for the facility for a given month. If the QCF equals or exceeds the average annual capacity factor for facilities of that technology type, as dtermined by the Energy Commission, the facility receives RRCCs in an amount equal to the capacity registered by the owner.

- Credits are tradeable among owners and retail sellers on an RRCC exchange established and maintained by the Energy Commission

- A substantial fine is to be paid by non-complying retail sellers, proceeds of the fine to support research and development in renewable technologies.

- RREGTs to include in-state hydro, geothermal, solar, wind, biomass, and "hybrids." Hybrids limited to 25 percent fossil fuel input.

- Registration of capacity values; calculation of qualifying capacity factors; auditing, certification, and issuance of credits; administration of the penalty fund are all the responsibility of the Energy Commission.

An issue of particular importance in the renewables area is raised by the fact that the tradeable credit represents additional cost for California retail ratepayers. (This is true of both an energy credit and a capacity credit.) The RRCC proposal properly limits credit eligibility to California facilities, not facilities located in other states which do not have similar electric generation portfolio requirements and programs, and which do not provide any of the local environmental and economic benefits for which California ratepayers are paying. This aspect of the proposal effectively refutes arguments for exclusion of hydropower based on the ability of Northwest hydro to "swamp" the market. Sales of that energy may indeed impact California energy markets because of its cheapness and (with re-operation) environment beneficence, but such sales will be irrelevant in terms of the renewable capacity credits designed to sustain the California renewable portfolio. Only in-state facilities qualify.

This aspect of the proposal (limitation of credit eligibility to California facilities) also implicates the Commerce Clause of the U.S. Constitution. Since Congress has, in the Energy Policy Act of 1992, directed the several states to develop integrated resource plans that include consideration of renewables, there is no issue of express pre-emption by Congress that might invalidate an RRCC program. Rather the concern is that the limitation on capacity eligibility to California-located facilities may implicate the "dormant" Commerce Clause, that is, the potential for future Congressional action that may by implication invalidate "burdens" placed by individual states on interstate commerce. The concern is misplaced.

In the RRCC approach, there is no discrimination "in favor of California renewable generators and against out-of-state renewable generators" with respect to sales of energy or power -- the commodity or "article of commerce" that flows among the states. Every generator is entitled to sell electric energy at retail and at wholesale within California at a market clearing price or at a contract price. There is no prohibition or restriction of any kind on energy imports. There is no exclusion from a "market for renewable energy sales that satisfy the portfolio standard" because the standard is not predicated on sales of energy. *The RRCC standard is satisfied by inclusion of qualifying renewable capacity in a generating resource portfolio that is scaled to meet demand requirements*.

The application of the RRCC requirement is not applied in a manner that discriminates against interstate commerce. All retailers, regardless of location, have the same requirement predicated on the retail sales nexus each retailer has with end-use buyers located within California. It is not obvious that a discrimination analysis predicated on interstate traffic in energy applies to such an arrangement because the creation of an RRCC under this proposal is not based on any transactions involving commodities or articles of commerce.

Typical discriminatory activities that run afoul of the "dormant" Commerce Clause include:

1) Prohibitions on commodity imports into a state, direct or indirect. Wyoming v. Oklahoma, (1992), 112 S. Ct. 789
2) Prohibitions on commodity exports out of a state. Hughes v. Oklahoma, (1979), 99 S. Ct. 1729; Pike v. Bruce Church, Inc., (1971), 397 U.S. 137
3) Higher taxes on commodity imports than on local commodities. Oregon Waste Systems v. Department of Environmental Quality, (1994), 114 S. Ct. 1345 (different

waste disposal fees); Associated Industries of Missouri v. Lohmann, (1994), 128 L. Ed. 2d 639 (higher use tax for out-of-state sales than sales tax on in-state sales of identical goods); Bacchus Imports Ltd. v. Dias, (1986), 104 S. Ct. 3049 (excise tax exemption for local liquors); New Energy Co. of Indiana v. Limbach, (1988), 108 S. Ct. 1803 (motor vehicle fuel excise tax credit for locally produced ethanol); West Lynn Creamery v. Healy, (1994), 129 L. Ed. 2d 157 (obligation to pay milk surcharge applied to all milk retailers but proceeds distributed only to local milk producers)
4) Stated preference or market set-asides for local commodities. Alliance for Clean Coal v. Bayh, (1995), 72 F. 3d 556 (7th Cir. Ind.); Alliance for Clean Coal v. Miller, (1995), 44 F. 3d 591 (7th Cir. Ill.)

The RRCC requirement does not neatly fall into any of these fact patterns. If there is discrimination, it is with reference to what facilities are eligible for an RRCC. Local facilities are eligible because they provide local environmental mitigations, remediations and enhancements. This is consistent with a long-standing distinction in Commerce Clause jurisprudence between economic protectionism on the one hand and health and safety regulation on the other. Sporhase v. Nebraska ex rel. Douglas, (1982), 458 U.S. 941, citing H.P. Hood & Sons v. Du Mond, (1949), 336 U.S. 525.

The RRCC approach requires that all retailers, regardless of location inside or outside the state, acquire capacity credits which are created with respect to facilities that operate in California and whose output is consumed in California. The issue posed by this approach is whether the restriction of capacity credit *eligibility* to local renewable facilities [and the denial of credit eligibility to out-of-state facilities] violates the Commerce Clause. Since there is no impact on the interstate sale of electric energy in California and no discrimination with respect to traders (buyers and sellers of energy) based on their participation in interstate commerce, the impact of capacity eligibility on interstate energy markets is at best incidental. Any incidental impact is arguably justified by the fact that out-of-state renewables do not provide the same local environmental benefits and enhancements, and do not support a Congress-authorized state-level integrated resource plan in the same way that local renewable facilities do. Pike v. Bruce Church, Inc., supra.

Finally, achieving local environmental benefits associated with local renewables through a capacity credit program is less burdensome than a “public benefits charge” levied on retailers, the proceeds of which are distributed to local renewable generators. Such an approach may be unconstitutional, based on the analysis of the Massachusetts milk subsidy program conducted by the Court in West Lynn Creamery, supra. Or, alternatively, a “public benefit charge” approach, in order to pass constitutional muster, may require California ratepayers to subsidize windfarms in Nevada and biofuel incinerators in Arizona, not a policy result contemplated by the Commission or the Legislature.

b. Proposed Legislative Text

DRAFT LEGISLATIVE LANGUAGE
TO IMPLEMENT A RENEWABLE PORTFOLIO STANDARD
THROUGH A RENEWABLE RESOURCE CAPACITY CREDIT

SECTION 1. Section 454.3 of the Public Utilities Code is repealed.

SECTION 2. Section 701.3 of the Public Utilities Code is repealed.

SECTION 3. Chapter 7 is added to Part 1 of Title 1 of the Public Utilities Code to read:

CHAPTER 7
RENEWABLE ENERGY RESOURCES

Article 1. Findings and Policy.

3201. The Legislature finds and declares that:
(a) The State of California has a system of electric generation that is the most technologically diverse in the world;
(b) The diversity of the California electric generation mix is the result of more than two decades of state policy promoting technological innovation and resource diversity, including electric generation from renewable sources;
(c) The Congress of the United State has delegated to each state the authority to develop integrated resource plans for electricity supply and consumption within the state that balance local environmental, public health, economic and financial considerations;
(d) California has exercised the authority delegated by Congress to adopt an integrated resource plan process that protects its environment and promotes the public health and safety of its residents by, among other things, promoting development of local facilities that utilize renewable resource electric generation technologies;
(e) Many facilities located in California and utilizing renewable resource electric generation technologies provide unique local environmental and public health and safety benefits and enhancements, such as flood-control, fish and wildlife habitat protection and enhancement, air pollution reduction in impacted California airsheds and other forms of environmental remediation directly related to their operation in California;
(f) It is in the interest of California citizens to retain and expand the environmental and public health benefits of renewable sources of electric generation as an element of its integrated electricity supply resource plan;

(g) California policy has resulted in substantial investments by California utilities and electric suppliers in electric generation projects utilizing renewable resource technologies, located in California, that have specialized operating constraints related to environmental remediation and mitigation and cost structures different from standard fossil fuel-based generation technologies;
(h) It is in the interest of California citizens to promote technological diversity and innovation in electricity generation, including electric generation from renewable sources, as an element of its integrated electricity supply resource plan;
(i) It is in the interest of California citizens to protect California utilities from severe financial hardship resulting from investments in renewable electricity generation facilities that appear uneconomic in the short-run as an element of its integrated electricity supply resource plan;
(j) Sharing the costs and benefits of renewable electric generation among all retail consumers of electricity in California is just and reasonable and in the public interest;
(k) The use of market-based mechanisms to support and value investment in electricity generation from renewable sources is preferable to direct or indirect taxation schemes for that purpose;
(l) the California Public Utilities Commission has expressed its preference for a market-based mechanism as the means to provide for renewable resources;
(m) market-based mechanisms should promote efficient utilization of existing electric generation facilities employing renewable resources in California and should provide sufficient stability and predictablity so that investments in renewable electric generation technologies located in California can continue to be made;
(n) market-based mechanisms should permit renewable electric generation technologies to compete among themselves on a fair and equitable basis, recognizing that various renewable electric generation technologies have differing operational, financial and cost constraints.

3202. It is the policy of the State of California that retail sellers of electricity include in their electric supply portfolios a substantial proportion of electric generation capacity that utilizes renewable resource technologies.

Article 2. Renewable Resources Portfolio Requirement

3205. For purposes of this chapter “commission” means the California Energy Conservation and Development Commission created by the Warren-Alquist Act of 1974, Public Resources Code, Sections 25001 and following.

3206. For purposes of this chapter electricity is “for sale in California” if it is delivered to a retail seller or to a power pool from which retail sellers purchase electricity.

3207. For purposes of this chapter "power pool" means any arrangement approved by the Federal Energy Regulatory Commission for the dispatch of electric generation on a coordinated basis.

3208. (a) For purposes of this chapter "renewable resource electric generation technology" means electric generation technology producing electricity energy from hydro power; geothermal steam; wind; solar energy; combustion of solid fuel biomass; combustion of gas derived from landfills or other processing of bio-mass; eligible hybrid technologies and such other technologies as the commission may certify pursuant to section 3220.
(b) Hybrid technologies are technologies that utilize a renewable energy source such as solar energy or biomass and a fossil fuel energy source such as natural gas or petroleum-based fuel; an eligible hybrid technology is one for which the fossil fuel component represents less than 25 % of total energy input.
3209. For purposes of this chapter "renewable resource capacity credits" means the credits issued by the commission pursuant to section 3216.

3210. For purposes of this chapter retail sellers of electricity include electric corporations, municipalities, municipal utility districts, public utility districts, irrigation districts, power marketers, and any other person or entity who sells electricity to ultimate end-use consumers located in California, whether or not such person owns distribution, transmission, or generation facilities in California.

3211. Beginning on January 1, 1999 and each year thereafter, each retail seller of electricity shall, on an annual basis, certify to the commission that, during the preceding twelve months, it has obtained and cancelled renewable resource capacity credits representing 18 percent of the sum of its monthly coincident peak loads for those months.

3212. Each retail seller of electricity shall report to the commission the monthly and annual total of its retail electricity sales, the total electric energy delivered to end-use consumers derived from each eligible renewable resource electric generation technology and the date and hour of its monthly peak loads on an aggregate basis.

3213. A retail seller of electric energy who fails to comply with the requirement of section 3211 shall pay a fine equal to 1 mill ($0.001) per kilowatt-hour delivered to its retail customers during the preceding year into the Renewable Portfolio Research Account, established pursuant to Article 4.

Article 3. Renewable Resource Capacity Credits

3215. (a) The commission shall issue renewable resource capacity credits monthly to owners of eligible renewable resource facilities that meet the following criteria:

(1) the facility is located in the State of California;

(2) the facility utilizes a renewable resource electric generation technology;

(3) during the preceding month the facility met the qualifying capacity factor requirement pursuant to section 3217.

(b) the commission shall issue a credit for each increment of 100 kilowatts of capacity registered by the owner pursuant to section 3218.

(c) Upon issuance, the owner of the renewable resource capacity credit may retain or sell it to any exchange participant in the Renewable Resource Credit Exchange established by the commission pursuant to section 3219.

(d) A credit shall be valid for twelve months following its issuance or until its cancellation.

3216. (a) Renewable resource capacity credits shall be issued by the commission upon receipt from the owner of a verified statement of the preceding month's electricity output from facilities utilizing renewable energy technology and confirmation by the commission that the facility has met the qualifying capacity factor requirement established by section 3217.

(b) The commission may audit or investigate any owner to determine the accuracy of the statement.

(c) The commission shall issue rules and regulations for reporting the operational basis for the credits; for certifying, issuing and cancelling credits; and for extinguishing credits at the conclusion of the twelve month period.

3217. (a) Each facility for which a renewable resource capacity credit is issued shall operate at a qualifying capacity factor for the month for which a credit is received, as determined by the commission.

(b) The commission shall establish a facility capacity factor for each facility using a renewable resource electric generation technology as follows:

(1) The commission shall determine the electric energy output of the facility delivered to the transmission grid for sale in California and shall determine a monthly capacity factor based on such delivery and the registered capacity value for the facility established pursuant to section 3218;

(2) The facility capacity factor for any month shall be the rolling average of the monthly capacity factors for the facility during the preceding twelve months;

(c) The commission shall establish an average annual capacity factor for all facilities of that technology type located in California. The average annual capacity factor shall be based on the ratio of average annual energy output over a representative period of years, as determined by the commission, to rated capacity.

(d) If the facility capacity factor is equal to or greater than the average annual capacity factor, the qualifying capacity factor requirement shall be satisfied for that month.

3218. (a) The owner of each facility located in California utilizing a renewable resource electric generation technology shall register with the commission a capacity value for the facility, measured in kilowatts. The capacity value may be any amount up to the rated capacity of the facility.
(b) The registered capacity value shall be the basis for certification of compliance with the qualifying capacity factor requirement and the issuance of renewable resource capacity credits by the commission.
(c) An owner shall not change the registered capacity value for a facility for three years after registration.
(d) The commission shall issue rules and regulations for the registration and modification of facility capacity factors by owners.

3219. (a) The commission shall create the Renewable Resource Capacity Credit Exchange, which shall be the market for buying and selling renewable resource capacity credits for purposes of compliance with the Renewable Portfolio Standard established by section 3211.
(b) Retail sellers of electricity and owners of renewable resource electric generation technology may buy and sell credits on the Exchange.
(c) Retail sellers and owners of facilities utilizing renewable resource electric generation technology shall register with the commission as exchange participants.
(d) The commission shall issue rules and regulations governing registration of participants, disclosure of prices, financial responsibility of buyers and sellers, settlements and such other matters that, in the commission's judgement, will facilitate operation of the exchange.

3220. The commission may certify additional renewable resource electric generation technologies whose characteristics are consistent with section 3208.

Article 4. Renewable Portfolio Research Account

3225. (a) There is the Renewable Portfolio Account in the General Fund.
(b) Fines paid by retail sellers who fail to meet the standard established by Section 3211 shall be deposited in the Renewable Portfolio Account.

3226. Funds in the Renewable Portfolio Account shall be appropriated annually to the commission and used to support research and development projects that improve the efficiency, cost effectiveness, and marketability of renewable resource energy technologies, as determined by the commission.

3227. The commission shall adopt rules and regulations for determining renewable energy research and development projects eligible for funding from the Renewable Portfolio Account.

3. Detailed Reponse to Working Group Issue List

a. What Is the Obligation?

a.1. How is "renewables generation" defined for purposes of qualifying for tradeable "renewable energy credits" (RECs) under this proposed program? Do existing and incremental utility-owned renewable-resource generation qualify for Renewable Energy Credits?

Renewable electric generation is defined to include hydro power, geothermal, solar, wind, biomass, and hybrids, which is defined as a technology that utilizes no more than 25 percent fossil fuel as its primary energy source. *The proposal is predicated on credits for renewable capacity, not renewable energy.* Existing facilities are eligible.

a.2. What are renewable energy credits? How do they relate to energy portfolio management?

The proposal is predicated on credits for renewable *capacity*. They do not relate directly to energy portfolio management. They relate to management of the generation capcity portfolio of the state as a whole. In that sense, the proposal is an aspect of integrated resource planning as practiced by California. However, the generation of energy from renewable facilities is necessary to produce capacity credits, so there will be energy produced from renewable facilities available for sale at market or contract prices.

a.3. How are a diversity of renewables encouraged?

The renewable portfolio capacity standard is high enough that no single renewable technology can produce all of the necessary credits.

a.4. Are currently high-cost technologies or pre-commercial technologies fostered by this program?

Consistent with the overall goal of electric restructuring of reducing electric energy costs, this proposal does not selectively encourage high-cost technologies or precommercial technologies. Rather, it creates a secondary market for renewable capacity credits that afford owners and operators of renewable electric generation facilities an opportunity to generate a revenue stream above that which would be created through the operation of the electric energy market alone. The additional revenue stream pays for the identifiable environmental and resource diversity of benefits that California-based facilities provide to California ratepayers.

a.5. How is renewable self-generation handled? Is self-generated renewable energy eligible for Renewable Resource Capacity Credits (RRCCs) [Renewable Energy Credits (RECs)], or for other means of support?

This proposal does not provide any ratepayer-funded support for renewable self-generation beyond the internal economics of the project itself.

a.6. How are hybrid fossil-fuel/renewable facilities handled?

Hybrids are eligible for renewable capacity credits if the fossil component is less than 25 % of energy input.

a.7. Does out-of-state generation qualify for RRCCs [RECs]? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

No. California energy sellers ought not be protected from out-of-state competition and are not afforded such protection by this proposal. In-state facilities that confer identifiable environmental benefits on ratepayers should be supported by local ratepayer dollars. In this proposal, those dollars are paid for renewable capacity credits.

a.8. If hydro is included, how are practical issues associated with hydropower handled?

The practical issues associated with hydro power are handled in the same way that the practical issues associated with other renewable technologies are handled: credits are generated through operation at an average level for the technology type. Energy output is marketed in the same way that all other energy is marketed. Any operational peculiarities of the particular facility for which credits are sought are taken account of through the decision to de-rate the facility's capacity. This option is available to all technology types, including hydro.

a.9. How is utility-owned distributed renewables generation handled? Does the proposal permit or prohibit RECs being awarded to distributed renewable power not sold through the Power Exchange? How does the proposal guard against self-dealing or cross-subsidization? For example, does the proposal permit RECs to accrue to applications that may involve the cross-subsidization of generation with T&D savings, or vice versa?

Utility-owned distributed renewables are eligible for renewable capacity credits so long as there is delivery to an end-user. As noted above, renewable self-gen is not eligible for ratepayer-funded assistance. The renewable capacity credit is radically divorced from energy markets and therefore avoids all market power or cross-subsidy issues.

a.10. What is the level for the requirement? How does this level relate to the level of renewables from 1990 to the present? Does the level of the requirement increase over time, and, if so, at what rate?

The requirement is 18 percent of the seller's annual average coincident peak demand. This number is not derived with reference to historical mwh sales. It is derived with reference to the ratio of renewable capacity, including hydro-electric capacity, to forecasted peak loads in the 1994 Electricity Report. No.

a.11. Describe how, if at all, the compliance obligation adjusts during a transition period.

Not applicable.

a.12. Does the proposal include a uniform requirement for all electric providers, including utilities, on a statewide basis?

Yes.

a.13. What is the time-horizon for the program?

Permanent.

a.14. Is the requirement established on a percentage of megawatts or percentage of megawatt-hours basis?

The proposal is capacity-based, and therefore is expressed in terms of megawatts.

a.15. Does the proposal establish floors for certain technology types? What is the rationale for a technology floor, if proposed?

No.

b. Where Is the Obligation to Comply?

b.1. On whom is the requirement applied? Is the requirement applied only to entities under the CPUC's jurisdiction, or is it applied statewide?

The requirement applies to all retail suppliers of electricity to end-users located in California. The requirement is applied statewide.

b.2. Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences?

All retail providers are treated the same, regardless of regulatory status.

b.3. What is the penalty for non-compliance? Should this penalty be interpreted as a cost-cap for the program?

The penalty for non-compliance is a 1 mill/kWh delivered by the subject retailer. This could be considered a "cost cap" for the program to the extent that it provides a quantifiable penalty amount for non-participation.

b.4. How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

Non-compliance is determined in a report to the Energy Commission that is responsible for all aspects of administering the program.

b.5. What provisions add flexibility to compliance, if any?

A failure to comply subjects the subject retailer to a substantial penalty. There are no provisions for a waiver, modification, or reduction of the penalty.

b.6. How does the program ensure that the policy and its costs are non-bypassable, such as the CTC or the Public Goods surcharge?

The requirement is placed on all retail providers of electricity, without exception. Only entities who are completely self-contained with respect to their electric consumption can avoid the requirement.

c. How Are Renewable resource Capacity Credits [Renewable Energy Credits] Initially Allocated?

c.1. How are RRCCs [RECs] generated from existing renewable facilities (QFs and utility-owned) initially allocate? What impact does the initial allocation have on whether a vigorous market for RECs, characterized by many buyers and sellers, forms?

Renewable capacity credits are created monthly by operation of the renewable facility at the average capacity factor scaled to the registered capacity for the facility. Once created, they are traded on the market. Compliance by retailers is determined every 12 months, and the price of credits will be determined by the supply, which in turn is determined by the output from renewable facilities.

c.2. What is the relationship of the allocation of renewable energy credits and the CTC or Public Goods surcharge? Will RECs accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid and avoid the CTC?

Renewable capacity credits are generated by renewable facilities without regard to their physical valuation or the value of their energy output for sale. The theory of this proposal is that renewable facilities confer benefits on California customers which California customers pay for by having their electric retailers buy credits from facilities' owners. To the extent that the stream of income represented by the credits supports continued investment in and operation of renewable facilities, it may affect both the magnitude and the duration of "CTC" or other tax on customers' participation in trading on energy markets or exchanges as envisioned by the CPUC.

c.3. If customers or ratepayers are initially allocated RECs, how are the credits administered?

Customers are not allocated capacity credits.

c.4. How would the proposed Renewable Energy Credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make them more or less cost-effective to ratepayers?

To the extent that QF buyouts are attempts to buy down the long-term capacity payment obligation so that facilities can be closed, the effect of giving an additional value to the capacity in the form of a capacity credit could have a distinct impact on existing negotiations. Simply put, the capacity would have increased economic value to the extent that the facility can be operated. From the standpoint of the QF facility owner, the decision remains the same: if the market price for energy is equal or exceeds variable costs, retaining the facility, the capacity payment, and the capacity credit value will be an appropriate choice. From the standpoint of ratepayers who have been charged by the commission with sustaining a renewable component in their electric energy porttfolio, retaining operating renewable facilities in the hands of third-party owners who have an inducement to sell renewable energy should benefit them.

c.5. How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

The theory of a renewable portfolio requirement is the need to support high-cost technologies whose internal economics would not support their continued operation or deployment. Therefore, "windfall profits" ought not exist.

c.6. Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

To the extent that the proposal affords the owners of the renewable facilities a revenue stream in addition to that offered by the market-based price of energy, their value is enhanced. Any owner would make a decision about the retention or sale of the asset to a third party. The PUC currently has rules about allocation of gain on sale of utility asset between utility shareholders and ratepayers which this proposal does not address.

d. How Is the Program Administered?

d.1. What agency certifies the RRCCs [RECs]?

The Energy Commission.

d.2. What mechanisms are proposed for trading of RRCCs [RECs]? How do the trading mechanisms relate to the initial allocation of RRCCs [RECs]?

A credit exchange.

d.3. What mechanisms are proposed for program oversight and mid-course corrections?

An explicit authorization of the Energy Commission to adopt regulations which includes amendments to regulations.

d.4. What agency monitors and enforces compliance with the program, and how is it carried out?

The Energy Commission.

e. Cost-Related Issues.

e.1. What are the costs associated with the program and who pays?

The costs associated with the program are not susceptible of immediate quantification, because it is not clear how capacity credits will be valued initially. This same uncertainty with respect to initial valuation appeared in the SO2 trading program under the Clean Air Act. In that program, the development of a robust price took about a year after credits were issued and trading was authorized.

e.2.   What cost-containment measures, if any, are provided?

None, unless the penalty (1 mill/kwh sold) is viewed as cap.

e.3.   If the program utilizes floors for certain technology types, what are the implications in terms of costs and benefits?

There are no floors or quotas specific to technology types.

e.4.   Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

No.

e.5.   How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities?

All renewable technologies receive credits based on their average operations. Operational characteristics specific to a renewable technology that might give it an advantage over another renewable technology are mitigated to some extent through this device. However, renewable facilities that are unable to survive under the dual revenue stream -- energy sales at market plus capacity credit sales -- will be discouraged. This would probably be the case with technologies that have both high capital costs and high operating costs.

New renewable facilities will be built when owners can observe an opportunity to profit based on the dual revenue stream generated by energy sales and capacity credit values.

e.6.   What implications, if any, does the proposal have in defining the roles of the LDC and of competitive suppliers of electricity?

Since the proposal applies to all retail sellers on an equal basis, it has no specific implications in defining the respective roles of LDC and other suppliers.

e.7.   What is the consistency of this proposal in relation to cost-related guidance provided by the CPUC Roadmap?

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f. How Does the Program Fit with Other Aspects of Electric Industry Reform?

f.1. Is the program compatible with the existence of an Independent System Operator? A Power Exchange? A Direct Access Market? Is the proposal consistent with the Commission's view of the role of the Power Exchange and ISO?

(a) Yes. (b) Yes. (c) Yes. (d) Yes. The proposal is independent of the operation of the energy markets, bulk, wholesale or retail.

f.2. Is the proposal dependent in any way on the Power Exchange or ISO? If so, are any additional protocols necessary?

The proposal is independent of the operation of the energy markets, bulk, wholesale or retail.

f.3. Does the proposal resolve conflicts of interest between distribution and competitive retail service? If so, how are they resolved?

The proposal is unrelated to energy delivery mechanisms.

f.4. How does the program avoid conflicts of jurisdiction between state and federal levels?

Federal law delegates to the states decisions about integrated resource planning and the definition of retail service areas within the state. The proposal respects this state/federal allocation of power as articulated by Congress. There are no state/federal jurisdictional issues unique to this program or radically different from those raised by California's specific approach to electric restructuring. Given the jurisprudence developed under the Federal Power Act, the Public Utility Regulatory Policies Act (PURPA), and the Energy Policy Act of 1992 (EPAct), concerns based on the "dormant" Commerce Clause are probably overstated.

f.5. What is the relationship between the proposal and Direct Access "Green Marketing"?

This proposal involves a radical separation between the energy market and the supplemental income stream represented by capacity credits. To the extent that "green marketing" involves the attempt to label electrons as "green" for marketing purposes, it is problematic. The creation of capacity credits facilitates honest claims about the utilization of renewable sources, and therefore facilitates “green marketing” based on payments to support specific identifiable renewable facilities. This is one way to make “green marketing” accountable.

f.6. What is the relationship between the proposal and performance based ratemaking (PBR)? Does the proposal place RECs under PBR, or exclude RECs from PBR?

Renewable capacity credits are outside any existing or proposed PBR mechanism.

f.7. Does the program create any potential market power problems involving the generation market or RECs?

No.

f.8. How does the proposal relate to any consumer protection or consumer education efforts?

The proposal does not involve any consumer education issues.

f.9. How, if at all, does the proposal relate to RD&D programs funded by the Public Goods Charge?

The proposal does not relate to RD&D programs funded by the Public Goods Charge.

f.10. How, if at all, does the proposal relate to energy efficiency programs funded by the Public Goods Charge?

The proposal does not relate to energy efficiency programs funded by the Public Goods Charge.

f.11. How does this proposal affect the CEQA compliance work recently initiated by the CPUC?

To the extent that the proposal takes account of all existing renewable resources, including hydro, it facilitates a thorough and complete appraisal of both the existing electric generation system and plausible future scenarios. Any approach that omits from evaluation a component of the generation mix as significant as the bloc represented by hydro in California creates serious problems for environmental evaluation.

g. Legislative Requirements

g.1 Can the CPUC implement this proposal by itself, or is legislation required? What would the legislative requirement be?

Legislation is required, in substantially the form in which the proposal is embodied.

g.2 What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the CPUC's 1998 implementation goal?

Implementation of the proposal requires legislation, which could be enacted in the 1997 legislative session.

4. Positions of the Parties in Favor/Neutral/Oppose

Comments of the CPUC's Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

DRA opposes this proposal because:

1. Inclusion of hydro will result in subsizidation of a resource that is fully competitive with other generating sources.

2. A capacity-based program would be unnecessarily complex.

3. Out-of-state hydro could swamp the portfolio standard, displacing other renewable technologies. Thus, it could be better to have no renewables program than to have this one.

4. NCPA's arguments are false that a capacity-based program avoids complications from the interstate commerce clause of the federal constitution regarding exclusion of out-of-state renewables.

5. Credits accrue to UDC-owned distributed renewables. UDC ownership of distributed renewables would conflict with unbundling and other key aspects of restructuring.

Comments of AWEA

OPPOSE. This proposal includes hydro renewables, and is based on capacity rather than generation of kWh, but includes energy factors to qualify the capacity basis. In order to use capacity as a basis, the proposal introduces numerous artificialities and rules, and depends on regulatory decisions rather than market forces to administer. By including hydro, the proposal calls for support of a resource that is mature and competitive with non-renewable generation, using up scarce support funds unnecessarily. Limiting the hydro to in-California locations is likely to violate the Commerce Clause, with the result that out-of-state hydro would dominate the renewable portfolio.

Comments CBEA

Concur with AWEA. Basing the standard for support on capacity, as this proposal does, rather than energy produced, fails to provide incentive to generate more efficiently and cheaply. This proposal rewards lower capacity plants as much as high capacity plants. This scheme would require other, non-hydro renewables to compensate for seasonal and annual fluctuations in hydro generation, denying them long-term certainty of market, and penalizing them for hydro's variations. Since a regulatory agency would need to determine the capacity required of hydro plants, an administrative burden and disputes are likely in administration of this approach.

Comments of GEA

Concur with AWEA and CBEA. This proposal includes both mature, fully-competitive hydro resources and new and/or environmentally mitigated hydro, the latter of which would be more expensive and possibly require support for economic viability, although few new hydro projects may be built. No competitive generation resource, renewable or not, should be supported. With the administrative determinations required to implement this proposal, and the constant, rolling window examination of performance data needed for certification, this program would pose a high regulatory and administrative burden. The potentially required inclusion of out-of-state hydro could destroy the in-state renewable portfolio standard.

Comments of Some Surcharge/Production Credit Proposers

(Note: Where Surcharge/Production Credit Proposal supporters' names appear independently in these "Position of Parties" subsections, their position is not included in the following position statement made on behalf of the remaining supporters.)

<u>Oppose:</u>

4. ***<u>Increases MRPR by 80% to include hydro, but ignores impacts on others</u>: Rolling capacity factors mitigate hydro's uneven annual delivery, but other renewables must adjust their own production seasonally to compensate for hydro fluctuations.***

5. ***<u>Forces continual oversight:</u>* Oversight of rolling 12 months' data is required to ascertain certification.**

6. ***<u>Includes hydro which may encourage over development</u>:* California's hydroelectric resources are fully developed. If over-development of this valuable resource is encouraged by availability of financial supports, damage to California's environment may result.**

7. ***<u>Inappropriately directs penalty funds to support RD&D</u>:* The CPUC decision already provides for RD&D funding through Public Goods Charges.**

Comments of Orange County, Sonoma County, the City of Sacramento, NEO Corporation

We oppose this proposal because it has all the complications and discriminatory characteristics of the BRPU. It includes hydro, something we do not favor. It rewards technologies with poor capacity factors. We prefer nondiscriminatory treatment of all technologies - no tiers, set asides or engineered adjustments to capacity. The market would best be served with a price only auction for the supply of renewable energy.

Comments of the Union of Concerned Scientists

Oppose.
Bad Points: REC based on capacity instead of energy leads to perverse incentive for low capacity factor renewables. Inclusion of hydro subsidizes mature, fully commercialized technology, while doubling cost of compliance for same non-hydro renewables goal. Low 1 mil/kWh * delivered energy non-compliance penalty, roughly equivalent to a 0.55 cent/kWh REC non-compliance penalty (given 18% MRPR), encourages non-compliance, turning competitive program into administrative program by creating penalty fund. All or nothing penalty does not encourage partial compliance where full compliance not possible below cost cap. Does not support renewables growth/resource diversification since MRPR does not increase.

Comments of Los Angeles Department of Water and Power (LADWP)

DWP favors the continued support of renewable resources, however, it should be made clear to reviewers of this report that NCPA's proposal does not represent the position of all municipal utilities. The level and diversity of Californiais renewable resource mix should be established by the state legislature and the above-market cost for supporting renewable generation should be uniform throughout the state. The procurement of renewable resources should be the responsibility of some state entity for the state power pool and the cost of compliance should be borne by all customers served by the UDC on a non-bypassable basis.

Comments of Southern California Edison

The NCPA proposal is similar, in some respects, to the AWEA proposal, although there is not a separate biomass requirement. Difficulties with this proposal stem from the inclusion of hydro and use of capacity defining the purchase requirement.

Hydro should not be included in this program because it is generally cost-competitive, highly developed, and there are few, if any, environmentally acceptable, sites for new dams.

The requirement should not be based on capacity since this adds administrative complications, including the estimatation and tracking of the capacity factor of each facility that participates in the program.

Comments of CalSEIA/SEIA/CEC/ETDD

OPPOSE

Penalizes High Capacity Factor Technologies: Biomass and geothermal have high capacity factors versus wind and hydro yet proposal only requires a plant to match average capacity factor for its technology. Electric generation costs compete on energy cost not capacity factor, but this proposal rewards high capacity, high capital cost technologies the same as low capacity, low capital cost technologies. This unfairly compensates low capacity technologies.

Penalty Inapproriately Structured: Penalty is based on kWh while requirement is based on kW. Penalty appears to be too low and would encourage non-co mpliance. Also, penalty is all or nothing, not proportional to amount of compliance, thereby also encouraging payment of penalty rather than compliance.

Comments of the California Integrated Waste Management Board

Oppose: Hydroelectric power as an eligible renewable technology will tend to limit the amount of other renewables. The large volume of low cost hydro available both in-state and out-of-state has the potential to dwarf/drown competing renewable technologies.

The concept of the minimum purchase requirement is to allow for the existence of generational technologies which cannot compete with "all comers" in a spot market. There are fewgenerational technologies that can economically compete with hydro.

Using capacity as the standard may distort the pricing of competing technologies and appears to conflict with the direction of PX pricing.

Comments of Don Augenstein

Fairness requires that hydro in the renewables portfolio should entail little cost advantage or disadvantage compared to other renewables' use. Only incremental, relatively-high-cost hydro can meet this condition and it seems low cost hydro should be excluded. Yearly hydro fluctuation must be somehow managed to not adversely affect other renewables. "All or none" penalty seems too stringent; higher capacity factor renewables are effectively penalized. To date at least, the NCPA proposal does not resolve these issues, but further work could help toward resolution.

Comments of SoCAL Gas

OPPOSE - Relies very heavily on the CEC determination of capacity factors for specific facilities. Such detailed specifications invites regulatory disputes. Varying capacity factors by technology translates into varying subsidies on an energy basis, favoring renewable technologies with lower capacity factors and higher capital costs. The program lacks a cost cap. The 18% for dependable renewable capacity is based on outdated ER'94 forecasts for 1998 that implement BRPU renewable levels. The 18% is too high. The 1 mill penalty applied to all retail sales is punitive. Not crediting out of state renewables is not justfied. The inclusion of hydro leads to complications.

Comments of SDG&E

Oppose:

- No cost limitation.
- Primarily subsidizes already-subsidized existing projects instead of new development.
- Unequal cost: burden on consurners.
- Relies on arbitrary penalty structure to force compliance, based on entire retail sales as opposed to non-compliance with the proposal's capacity-based minimum.
- Inconsistent with electric restructuring; mandates distribution companies to maintainresource portfolio instead of relying on the competitive market.
- No performance penalty if the renewable developer does not provide capacity.
- Administratively burdensome and complex.

Comments of PG&E

PG&E believes that all the RPS proposals may be basically incompatible with the increasingly competitive generation market. This particular proposal, while very complex to implement and monitor, does have the advantage of allowing hydro to be a renewable while avoiding the problem of imported hydra taking up all the credits. PG&E would prefer that this proposal contain some sunset or program review provisions.

D. Single-Band Renewable Portfolio Standard ("SBRPS")

Submitted by: Southern California Edison Company and Pacific Gas & Electric Company

1. Interpretation of Commission's Goals and Rationale for Strategy

This proposal interprets the Commission's December 20, 1995 policy on renewables to mean that proposals to implement the Commission's direction should maintain the level of resource diversity within California and should achieve this objective by providing for competition among both existing and new resources. Maintenance of the level of resource diversity may be achieved by replacing existing projects with new projects. The policy does not require maintenance of diversity among renewable resources.

In order to provide flexibility in achieving this objective at the lowest cost, the Commission has indicated a preference for market-based approaches. The Commission has also recognized that all customers, including direct access customers and customers of investor-owned utilities and municipal utilities, should be responsible for achieving the objective of resource diversity.

This implementation proposal meets these objectives by establishing a renewables purchase obligation of 10 percent on all sellers of electricity to end-use customers under the Commission's jurisdiction no later than January 1, 1998. Unless this obligation is extended statewide to all providers to end-use customers, including municipal utilities, through legislation by the end of the year 2000, the obligation would be eliminated. This obligation is imposed on providers to end-use customers subject to the requirement and may be fulfilled with solar, wind, biomass, and geothermal energy. The obligation is held fixed for the initial three years of the program.

2. Program Overview and Description

a. Overview

This proposal is designed to implement the Commission's policy on renewables contained in the December 20, 1995 Policy Decision (D.95-12-063 as corrected and conformed by D.96-01-009) and further defined in the March 13, 1996 Roadmap Decision (D.96-03-022). In these decisions, the Commission indicated that its policy on renewables was designed to maintain California's resource diversity and encourage the development of new renewable resources[13]. The Commission indicated that its preferred approach for achieving these objectives was through the establishment of a Minimum Renewables Purchase Requirement (MRPR) to be implemented through a tradeable credit program[14].

b. Principles

Principles governing the MRPR implementation proposal submitted by Southern California Edison Company (SCE or Edison) and Pacific Gas & Electric Company (PG&E) include:

- The MRPR program should be simple to explain and administer.
- The costs of the MRPR program should be explicitly capped.
- Implementation of the MRPR program should be consistent with implementation of the competitive generation market, independent of the Power Exchange and Independent System Operator (ISO), and impose no power purchase requirement on the Utility Distribution Company (UDC).
- The MRPR program should maintain the current share of renewables in California's generation portfolio and should allow cost-effective new renewable development to substitute for existing renewables.
- The MRPR program should balance economic, environmental, and other societal goals.

The parties identified with this proposal believe that it is consistent with the Commission's proposed minimum renewables purchase requirement and with the above set of principles. However, the parties do not necessarily endorse the MRPR approach over possible alternative approaches for achieving the Commission's resource diversity goal.

c. Overall Approach

A minimum renewables purchase requirement (MRPR) requires that entities selling power to end-users in California and subject to this requirement demonstrate either that they have purchased the required fraction of power from renewable energy sources or that they have purchased an equivalent number of tradeable credits. Compliance is subject to audit under the supervision of the program administrator.

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[13] "We are committed to establishing restructuring policies which maintain California's resource diversity for existing resources as well as encourage development of new renewable resources." "We continue to believe that a minimum renewables purchase requirement is the best approach to meet our resource diversity goals." pp. 147, 150, D.95-12-063 as corrected and conformed by D.96-01-009.

[14] "Credits for meeting this requirement would be tradeable, similar to tradeable permits programs adopted by Congress in the Clean Air Act Amendments of 1990 and the South Coast Air Quality Management District's Regional Clean Air Incentive Market, in order to allow retail providers the most flexibility in meeting this requirement." p. 150, ibid.

A renewable energy credit (REC) is created when one kWh of renewable energy is generated and sold into the California end-use market. Renewable energy may be generated and sold by a utility distribution company (UDC), by a non-UDC retail electricity supplier, by a generator affiliated with a UDC, and by an unaffiliated independent power producer.

d. Definition of Renewables

Generation resources defined as renewables for purposes of creating an REC include: biomass (including solid fuel biomass, solid waste-to-energy facilities, landfill gas, and anaerobic digester gas); geothermal; solar (including solar thermal electric and photovoltaics); and wind.

Generators may be located in or out of state, but they are required to sell to the California market. The California market is defined as any transaction that involves selling to a California end-user through a bilateral contract, selling to a California UDC or other distribution utility in California, selling to the Power Exchange, or selling to the Independent System Operator (ISO).

e. Minimum Level of Renewables in Portfolio

REC Target: For each seller's portfolio, at least 10% of all its kWh sold to California end-users each year shall be from renewable energy as determined by the holding of a sufficient number of RECs.

Growth in Renewables: The 10% REC target is fixed through the year 2000; growth in the share of renewables in the state portfolio comes from growth in load or over compliance with the standard.

Technology Set-Asides or Subsidies: No special set-aside or subsidy for individual renewable technologies is proposed. This provision does not preclude the state from promoting commercialization of emerging technologies through RD&D funds or other means. Generation from emerging renewable technologies would not be distinguished from other renewable technologies under this program.

f. Renewable Energy Credits

RECs are based on actual renewable generation from renewable sources as generated and metered. As a result, the following applies:

- generation from partially fossil-fueled source is only partially renewable,

- generation from off-grid renewable sources is not eligible for RECs, and

- only the net generation of a net-metered solar facility counts.

Allocation of the revenues from the sale of RECs (i.e., "ownership") depends on the status of the generation project. The following provisions are proposed for utility generation, independent generation subject to existing QF contracts (i.e., contracts signed prior to January 1, 1998), and independent generation not subject to existing QF contracts.

- Utility generation subject to traditional regulation: the RECs are owned by the utility; revenues from the sale of REC goes toward reducing CTC or other ratepayer costs.

- Independent generation, including existing QFs no longer under contract: RECs are owned by the generator and traded as the owner sees fit, including sale to environmental groups for "retirement".

- Generation subject to existing QF contracts: RECs are owned by utility on behalf of ratepayers; revenues from sales of these RECs go toward reducing CTC associated with QF contracts or other ratepayer costs.

This proposal supports the development of a competitive market for RECs. If the allocation of credits results in the control of RECs being concentrated among relatively few sellers, structural mechanisms (e.g., a competitive auction conducted by the state agency) are proposed to mitigate any potential market power.

g. Administration and Compliance

Specific administrative and compliance provisions under this program include:

- Program administration is the responsibility of a qualified state agency. Neither the Power Exchange nor the ISO are to have any administrative or monitoring duties.

- Retail and other end-use sellers are to report annually to the state agency, providing total kWh sales in California subject to requirement, and surrendering required RECs.

- A three-month "true-up" period is proposed at the end of each year for self-auditing, end-of-year-transactions, and reporting.

- Renewable generators report on a quarterly basis qualifying kWh generation (i.e., renewable generation sold into the California market) to state agency responsible for administering the program.

- The state agency checks the compliance of retail and other end-use providers, and conducts spot audits of both providers and generators.

- Confirmation of compliance is sent to individual end-use sellers. Data on over- and under-compliance are provided annually to the end-use sellers and the public.

h. Cost Cap on Purchase of RECs

The state agency is to make available for purchase RECs at a set price per REC. The fee is specified as 2 cents/kWh for each REC, establishing the maximum compliance cost for this implementation proposal. This proposed fee establishes a cap on the maximum cost of the program. Any revenues collected by the state agency are to be used to promote renewable development.

i. Penalties for Fraudulent Behavior

Penalties or fines may be imposed by the state agency for end-use sellers or renewable generators found to have engaged in fraudulent behavior. Examples of fraudulent behavior would include the intentional underreporting of sales by the end-use seller and of overreporting of renewable energy production by the generator. The state agency is to assess and collect penalties or fines in these and other instances. Revenues from the penalties or fines are to be used to promote renewable development.

j. Time Horizon

Once implemented, the proposed program is to be revisited and modified, as determined to be appropriate, at the end of the year 2000 and every 5 years thereafter until the program is eliminated. Modifications may include changes in the structure of the program (e.g., target percentages, purchase fee for RECs, penalties, definition of renewables, etc.) as well as possible termination of the program. All modifications are to be consistent with legislative direction. If the legislature has not extended the program to municipal utilities by the end of the year 2000, the program will be terminated.

k. Legislation

This proposal may be implemented by the CPUC initially. The renewable purchase requirement may be imposed by the CPUC on IOUs and any other entities under its jurisdiction. Legislation is recommended to allow for a broad-based, state-wide program imposed equally on all parties including municipal utilities and special districts.

3. Implementation Questions

a. What is the Obligation?

a.1 How is "renewables generation" defined for purposes of qualifying for tradeable "renewable energy credits" (RECs) under this proposed program? Are existing and incremental utility-owned renewables included?

Generation resources defined as renewables for purposes of this program include: biomass (including solid fuel biomass, solid waste-to-energy facilities, landfill gas, and anaerobic digester gas); geothermal; solar (including solar thermal electric and photovoltaics); and wind.

All utility-owned renewable generation is included. The value of renewable credits for utility-owned renewables subject to traditional cost-based regulation (including performance-based ratemaking mechanisms) are flowed through to utility customers.

a.2 What are renewable energy credits? How do they relate to energy portfolio management?

A Renewable Energy Credit (REC) is a tradeable "certificateÓ based on one kilowatt-hour of electric generation from a renewable fuel source. RECs are denominated in kilowatt-hours (kWhs). A REC is created when: (1) one kWh of electricity is generated from a renewable fuel source; (2) that kWh is deemed to have been sold end-users in California; and (3) a satisfactory verification of (1) and (2) is made.

a.3 How is a diversity of renewables encouraged?

The competitive market will encourage a diversity of renewables to the extent the market values diversity of renewables. Individual sellers to end-users will have the opportunity to market different forms of renewable energy which also satisfy the obligation imposed by this program. The Commission did not establish renewable diversity as a goal for this program but only suggested that it be considered.

a.4 Are currently high-cost technologies or pre-commercial technologies fostered by this program?

This proposal does not envision the minimum renewable purchase requirement (MRPR) program as a technology commercialization program nor was this goal articulated in the Commission's Policy Decision. However, the MRPR program does help to close the gap between the cost of pre-commercial technologies and potential revenues from the market. By treating all technologies equally, the program does increase the demand and encourage further development for any pre-commercial technologies.

To the extent that certain technologies are "pre-commercial" and the Commission or legislature decides that the public interest is served by providing additional funding support to promote commercialization of specific technologies, a separate program supported could be established or the RD&D activity could be expanded to include "C" (i.e., commercialization). Either of these activities could be funded through a non-bypassable surcharge on all end-users.

a.5 How is renewable self-generation handled? Is self-generated renewable energy eligible for Renewable Energy Credits, or for other means of support?

Renewable self-generation is eligible if metered and if the generator either purchases and/or sells electric power to the grid.

a.6 How are hybrid fossil-fuel/renewable facilities handled?

Only the electric generation associated with the renewable fuel source is eligible for an REC. For example, a gas-assisted solar thermal project would "derate" every kWh generated based on the amount of heat content in the fossil-fuel used. The basis for "derating" the kWh generated would be established annually and subject to audit.

a.7 Does out-of-state generation qualify for Renewable Energy Credits? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

Out-of-state renewable generation deemed to be sold and delivered to California end-users qualify for RECs under this proposal. While there may be non-protectionist reasons to favor in-state generation over out-of-state generation, these arrangements are likely to be challenged as inconsistent with the Commerce Clause of the federal constitution.

a.8 If hydro is included, how are practical issues associated with hydropower handled?

Hydro power is excluded as discussed in question a.1. above.

a.9 How is utility-owned distributed renewables-generation handled? Does the proposal permit or prohibit Renewable Energy Credits from being awarded to distributed utility-owned renewable power not sold through the Power Exchange? Does the proposal permit Renewable Energy Credits to accrue to applications that may involve the cross-subsidization of generation with T&D savings, or vice versa?

The proposal permits RECs being awarded to distributed utility-owned renewable power, preferably after the Commission addresses and resolves the various issues regarding utility-ownership of all sources of distributed generation (e.g., fuel cells, small cogeneration, photovoltaics, etc.).

a.10 What is the level for the requirement? How does this level relate to the level of renewables from 1990 to the present? Does the level of the requirement increase over time, and if so, at what rate?

The level of the requirement is set at 10% of end-use provider sales for the state with the percentage share fixed for the initial three years of the program from 1998 through the year 2000. The level of the requirement for an individual retail provider is independent of whether the requirement is implemented for CPUC-jurisdictional customers or state-wide. For the state, generation from renewable fuel sources as a percentage of total generation has varied from 10 to 12 percent for the five-year period, 1990 to 1994.

a.11 Describe how, if at all, the compliance obligation adjusts during a transition period.

For the first three years of the program, the percent share of end-use sales is fixed at 10 percent. Growth in customer loads and extension of the program state-wide will result in increases in the level of renewable generation specified as the compliance obligation.

a.12 Does the proposal include a uniform requirement for all electric providers, including utilities, on a state-wide basis?

Yes. This proposal supports the Commission's stated preference that the obligation apply equally to all retail and other end-use sellers. Legislation is required to extend the MRPR to municipal utilities, special districts, and other end-use providers not subject to CPUC jurisdiction. A uniform requirement is reasonable for at least two reasons: (1) the benefits of renewables, including resource diversity and environmental enhancements, accrue to the economy and environment of the entire state; and (2) setting different levels for each entity, based on the resource diversity in the portfolios of individual utilities, even if adjusted gradually, would competitively disadvantage utilities with significant resource diversity.

a.13 What is the time horizon of the program?

Consistent with the Commission's December 20, 1995 Policy Decision, the MRPR program is to be revisited and possibly modified in the year 2000. If the MRPR program is continued beyond the year 2000, this proposal recommends that the MRPR program be revisited every 5 years thereafter. Possible modifications during the initial and subsequent reviews include changes, either increases or decreases, in the level of the requirement, changes in the REC purchase fee, changes in penalties, changes in the definition of renewables, and changes in the monitoring of the program. Termination of the program based on an assessment of the benefits and costs would also be considered.

All modifications should necessarily be consistent with legislative direction. If the state legislature has not extended the program or established an equivalent program for municipal utilities, the MRPR program would be terminated.

a.14 Is the requirement established on a percentage of Megawatts of percentage of Megawatt-hours basis?

Percentage of megawatt-hours basis.

a.15 Does the proposal establish floors for certain technology types? What is the rationale for a technology floor, if proposed?

No.

b. Where is the Obligation to Comply?

b.1 On whom is the requirement applied? Is the requirement applied only to entities under the Commission's jurisdiction, or it is applied state-wide?

If implemented by the Commission, the requirement would be applied to investor-owned utilities, direct access suppliers, and grid-interconnected self-generators transmitting power to another location. Legislation is required to apply the standard to municipal and cooperative utilities and special districts. This proposal supports state-wide application, but allows for implementation by the Commission through the year 2000.

b.2 Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences?

Under this implementation proposal, the 10% renewable purchase requirement applies to all entities selling to end-users in California. As a result, there are no differences in the treatment of regulated retail providers and other end-use providers, including unregulated retail providers.

b.3 What is the penalty for non-compliance? Should this penalty be interpreted as a cost-cap for the program?

A fee of 2 cents/kWh (1995 dollars) is imposed for each REC that a retail or other end-use provider does not surrender by the end of the three-month "true-up" period which follows each annual reporting period. The fee may be refunded the following year if the provider surrenders the RECs to cover the previous deficit in the next reporting period.

This penalty is higher than the expected value of RECs for the initial three-year period. The MRPR penalty also serves as a cap on the maximum cost of complying with this program. Similar provisions were incorporated in the federal SO_2 program and in the South Coast Air Quality Management District NO_x trading program (i.e., RECLAIM).

For the initial three years of the program, the state administrator could use the revenues collected through the penalties to promote renewable development or reduce the competitive transition charge (CTC) associated with QF contracts.

b.4 How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

Compliance of retail and other end-use sellers is determined on an annual basis with the surrender of credits sufficient to meet obligation which is defined as a percentage of annual sales to end-users. A state-designated administrator is responsible for determining non-compliance and for establishing administrative procedures to resolve disputes. Prior to the passage of legislation, the administrator will be designated by the CPUC. If the program is extended state-wide, the required legislation will designate the administrator and corresponding enforcement powers.

b.5 What provisions add flexibility in compliance?

A 3-month true-up period as well as the ability to purchase RECs from the administrator at the purchase fee if credits are unavailable provide flexibility in compliance.

b.6 How does the program ensure that the policy and its costs are non-bypassable, such as the CTC or the Public Goods surcharge?

All retail providers are required to be certified in order to sell to end-users in California and compliance with this program is a condition for certification

c. How are Renewable Energy Credits Initially Allocated?

c.1 How are Renewable Energy Credits generated from existing renewable facilities (QFs and utility-owned) initially allocated? What impact does the initial allocation have on whether a vigorous market for Renewable Energy Credits, characterized by many buyers and sellers, forms?

There are two parts to this question: (1) who receives the value of the RECs generated from existing renewable facilities, and (2) who controls the sale of RECs.

The value of the RECs generated from utility-owned renewable facilities is passed through to all customers (utility service and direct access customers) of the specific utility with an obligation to pay CTC. Similarly, the value of the RECs generated from QFs with utility contracts is passed through to all customers of the specific utility as well. The value of RECs generated from QFs without a utility contract (e.g., QF whose contract has been bought out) flow through to the developer.

The development of a vigorous market for RECs may be impeded if control over the sale of RECs is assigned to the current holders of the contracts. To address concerns regarding the potential exercise of market power, mechanisms to mitigate any potential market power associated with the initial allocation of credits will be developed by the administrator. Assignment of the credits through an auction is one approach worthy of consideration. This approach would separate control over the sale of RECs from the revenues received from these sales.

c.2 What is the relationship between the allocation of Renewable Energy Credits and the CTC or Public Goods Surcharge? Will Renewable Energy Credits accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid and avoid the CTC?

Under this implementation proposal, the value of RECs from existing renewables is allocated so as to reduce the CTC associated with QF contracts and utility-owned resources subject to cost-of-service regulation. The CTC charge is expected to be a non-bypassable charge to all customers whether or not they buy power from the UDC, the power pool, direct access or marketers. As a result, end-use customers with utilities with more than sufficient RECs to cover the purchase obligation will benefit from the proposed initial allocation of RECs.

The CTC mechanism proposed in the Commission's Policy Decision already provides an incentive for customers to disconnect from the grid entirely in order to avoid paying CTC. The MRPR program suggested by the Commission is effectively a subsidy to renewable energy and is expected to increase the average cost of power for end-use customers in California connected to the grid relative to the average cost of power for these customers without the MRPR program. Therefore, the MRPR program is expected to provide an additional incentive for customers to disconnect from the grid. The size of that extra incentive depends on the increase in the costs of power due to the REC requirement compared to the size of the CTC.

This implementation proposal requires that RECs only be provided to renewable generation metered and sold to end-users connected to the grid in the state; generation from off-grid renewable applications are not eligible to receive RECs. At a result, this implementation proposal is not expected to increase the incentive of customers with the potential to use renewables off-grid to disconnect from the grid since customers would not receive RECs for power generated from off-grid renewable applications.

c.3 If customers or ratepayers are initially allocated Renewable Energy Credits, how are the credits administered?

As described under question c.1, the customers or ratepayers receive the value of the Renewable Energy Credits derived from utility generation subject to cost-of-service regulation and from existing QF contracts. Assignment of RECs through a competitive auction is one of the mechanisms suggested above to address the potential exercise of market power.

c.4 How would the proposed Renewable Energy Credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make them more or less cost-effective to ratepayers?

As discussed under question c.1, the value of RECs created by QFs with existing contracts are passed through to the customers with responsibility for paying CTC (i.e., customers who take power from the grid whether they be UDC customers, direct access customers, or buying from the pool). Therefore, the allocation of RECs proposed makes no change per se in the status of existing QF contracts.

From the customer perspective, the existence of the MRPR program increases the value of existing contracts with renewable resources. As a result, the amount that is cost-effective for the customer to pay to buyout a contract with a renewable QF is reduced. (Note: This assumes that the MRPR is viewed as a new subsidy for renewables and not a substitute for existing subsidies.).

For contract buyouts previously negotiated, the cost-effectiveness of the proposed buyout is decreased if customers are assumed to be required to replace the renewable generation through the purchase of RECs and if an equivalent renewable subsidy was not assumed as part of the initial negotiations. At present, the structure of the proposed MRPR program and, as a result, the value of RECs to be generated by specific QF projects is currently so uncertain that it is hampering the evaluation of existing buyout proposals. This uncertainty associated with the MRPR program also appears to be discouraging future buyout negotiations at this time.

c.5 How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

According to Webster's New Collegiate Dictionary, a windfall is "An unexpected legacy, or other gain." Under this implementation proposal, the benefits or what some may term "windfall profits" accrue to the holders of the contract in the case of QF contracts and to utility-owned generation subject to cost-of-service regulation. In both instances, the value of the initial allocation is flowed through to customers to reduce the CTC associated with QF contracts and utility-owned generation subject to cost-of-service regulation. Neither the utility shareholders nor the owners of independent generators receive any windfall profits.

c.6 Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

The response to this question is similar in many respects to the response to question c.4. As with QF projects, the RECs potentially increase the value of utility-owned renewable resources (Note: Since hydropower is excluded, this question is of primary interest to geothermal projects held by utilities.). This increase in value would potentially increase the market price for these projects. However, this increased market price is not expected to encourage divestiture more than is presently the case.

d. How is the Program Administered?

d.1 What agency certifies Renewable Energy Credits?

Whether the CPUC or state agency designated through legislation administers the program, the certification process is expected to be similar. On a quarterly basis, the renewable generator will report to the CPUC or designated agency the amount of energy generated with renewable fuel sources. The report will be reviewed for completeness and a sample selected for possible audit. The RECs generated by the renewable generator will then be assigned as directed by the generator.

d.2 What mechanisms are proposed for trading of Renewable Energy Credits? How do the trading mechanisms relate to the initial allocation of Renewable Energy Credits?

No publicly sponsored trading market for RECs is proposed. Trading of credits is expected to occur in a spot market and through bilateral contracts. The initial control of the allocations is expected to be carried out in such a way as to ensure a competitive market.

d.3 What mechanisms are proposed for program oversight and mid-course corrections?

The administering agency is expected to have the authority to make adjustments in the implementation of the program on an ongoing basis. These adjustments are not intended to change either the level of the requirement or the allocation of revenues from the creation of RECs by existing renewable projects.

Prior to the end of year 2000, a comprehensive review is proposed. This review is to address both the anticipated benefits and costs of continuing with the program, of making modifications to the program, and of terminating the program.

d.4 What agency monitors and enforces compliance with the program, and how is it carried out?

The CPUC is responsible for monitoring and enforcing compliance if the program only applies to CPUC-jurisdictional entities (e.g., regulated retail providers, non-regulated retail providers, other end-use providers). Legislation extending the program to include municipals would designate a state agency as the administrative agency. This agency necessarily should have experience with monitoring and enforcing requirements similar to those established by the MRPR program.

e. Cost-Related Issues

e.1 What are the costs associated with the program, and who pays?

The costs associated with this program depend on the incremental costs of renewables that retail and other end-use providers are obligated to procure as demonstrated through RECs. The incremental costs depend on the market price as well as other developments affecting the relative price of renewables (e.g., technological breakthroughs).

Quantifying these costs is recognized to be speculative and sensitive to various assumptions. However, the costs associated with this implementation proposal are expected to be lower than programs with higher target levels and technology bands (i.e., special provisions for specific technologies). The costs associated with this implementation proposal are also expected to be lower than programs with similar requirements but less flexibility in how the requirement is met.

Who pays ultimately depends on the structure of the market and how sensitive market participants are to price. Initially, the costs of the RECs are expected to be passed through to customers by retail and other end-use providers since customers are not expected to be particularly price sensitive in the short-run.

e.2 What cost-containment measures, if any, are provided?

The purchase fee for RECs of 2 cents/kWh sets a maximum on the total costs of this implementation proposal. The costs per kWh of the program are expected to be lower. In addition, the review of the program in the year 2000 also allows for the costs of the program to be balanced with the perceived benefits.

e.3 If the program utilizes floors for certain technology-types, what are the implications in terms of costs and benefits?

Not applicable since the proposal does not utilize floors.

e.4 Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

Implementation will lead to the reallocation of the costs associated with the state's policy to promote renewable development. Presently, customers within the state do not pay the same amount for the state's current resource diversity. This implementation proposal would change this situation by imposing a uniform statewide requirement for all providers of electricity to retail and other end-use customers.

e.5 How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities?

Competition within and between renewable technologies is encouraged by allowing all technologies with the exception of hydro to create RECs to be used to meet the MRPR requirement imposed on retail and other end-use providers. See question a.2 for description of the requirements to create an REC.

Competition between existing renewable facilities and potential new facilities is encouraged by allowing both existing and renewable facilities to generate RECs to be used in meeting the MRPR requirement imposed on retail and other end-use providers.

e.6 What implications, if any, does the proposal have in defining the roles of the LDC and of competitive suppliers of electricity?

No implications. All retail and other end-use providers, including both regulated and unregulated, are treated equally under this implementation proposal. The proposal will not encourage or require any change in the role of the UDC other than what is envisioned in the Policy Decision.

e.7 What is the consistency of this general proposal in relation to cost-related guidance provided by the PUC roadmap?

By proposing a uniform requirement across all retail providers, this proposal may result in "cost-shifting" among franchise utility customers. For those utilities with a smaller share of renewables than the uniform requirement, these increased costs could increase the average rate. These costs may be excluded from the costs included in calculating the average rate for purposes of determining if the utility's rate are above the specified "rate cap".

f. How does the Program Fit with Other Aspects of Electric Industry Reform?

f.1 Is the Program compatible with the existence of an Independent System Operator? A Power Exchange? A Direct Access Market? Is the Proposal consistent with the Commission's view of the role of the Power Exchange and ISO?

Yes.

f.2 Is the proposal dependent in any way on the Power Exchange or ISO? If so, are there any additional protocols necessary?

No, the proposal does not rely on the Power Exchange or ISO for implementation, and no protocols are necessary to implement this MRPR proposal.

f.3 Does the proposal involve conflicts of interest between distribution and competitive retail service? If so, how are they resolved?

No, the UDC providing regulated retail service is treated the same as retailers and other end-use sellers providing competitive or unregulated end-use service.

f.4 How does the program avoid conflicts of jurisdiction between state and federal levels?

The primary state and federal jurisdictional issue concerns possible state-imposed restrictions on wholesale power transactions. This proposal avoids state/federal jurisdictional conflicts by allowing all generators selling into the California market to generate RECs and by applying the purchase requirement on retail and other end-use providers, which are subject to state jurisdiction.

f.5 What is the relationship between the Proposal and Direct Access "Green Marketing?"

Both this Proposal and Direct Access "Green Marketing" are designed to promote renewable development. However, this Proposal is not voluntary in that all retail and other end-use providers are subject to the MRPR requirement. Direct Access "Green Marketing" is voluntary on the part of retail and other end-use providers and their customers.

This proposal may facilitate "Green Marketing" by establishing the infrastructure for both defining renewable generation and generating RECs. A marketer of green power could sell a bundled product of RECs and electric power. By retiring the RECs sold, participating customers would be effectively increasing the share of renewables in the overall resource mix of the state.

f.6 What is the relationship between the proposal and Performance-Based Ratemaking? Does the proposal place Renewable Energy Credits under PBR, or exclude Renewable Energy Credits from PBR?

There is no explicit relationship between this MRPR proposal and PBR. The UDC may choose to propose that cost recovery of purchases of RECs be handled through a PBR mechanism. The objective of the PBR would be to provide the UDC with a reasonable opportunity to recover costs for the purchase of RECs while providing the UDC with appropriate incentives to efficiently procure RECs.

f.7 Does the program create any potential market power problems involving the generation market or Renewable Energy Credits?

No. Since the market for RECs is completely separate from the markets for power and ancillary services, the program does not create any potential market power problems involving the generation market. The potential concentration of ownership of the initial allocation of RECs is resolved by separating the allocation of the credits from control over the sale of the credits (see response to question c.1).

f.8 How does the proposal relate to any consumer protection of consumer education efforts? For example,

a) Rules for New Entrants. Does the proposal entail any licensing requirements for new entrants? Should compliance with the minimum renewables requirement be a condition of selling power at the retail level?

b) Consumer Education. Does the proposal require any consumer education? For example, how does the proposal protect customers from "green marketing" programs where marketers collect twice--once for credit sales and once for "green" power sales, thereby not increasing total green power? This could entail, e.g., amount of renewable energy they are purchasing that are supports by RECs, or statements regarding price stability of price risks associated with the seller's resource portfolio. Would RECs accrue to utilities from green pricing programs where utilities have unique customer information and access?

Compliance with this requirement is proposed as a condition of selling power to retail and other end-use customers. All retail and other end-use providers should be licensed, so that such licenses can be revoked in the event of noncompliance or fraud related to this and all other policies associated with providing retail and other end-use services.

Since the requirement is placed on retail and other end-use providers and not customers, this MRPR implementation proposal does not require any consumer education. The infrastructure developed for certification of RECs may facilitate green marketing and required consumer education and consumer protection provisions.

f.9 How, if at all, does the proposal relate to RD&D programs funded by the Public Goods Charge?

This proposal relates to RD&D programs funded by the Public Goods Charge in that it provides a "guaranteed" market for renewables (i.e., a market pull). Moreover, renewable energy generated by technologies funded by RD&D programs is not distinguished from renewable energy generated by commercialized technologies and is eligible to receive RECs. Also see response to question a.4.

f.10 How, if at all, does the proposal relate to the energy efficiency programs funded by the Public Goods Charge?

Under this proposal, RECs are based on renewable generation as generated and metered. Customer-side renewable energy applications that are not metered are not eligible for RECs under this MRPR proposal.

f.11 How does this proposal affect the CEQA compliance work recently initiated by the CPUC?

The Commission's MRPR proposal is one of many policies with environmental implications that should be considered as part of the CEQA compliance work. This implementation proposal is one of several implementation proposals which should be addressed as part of this work.

g. Implementation Steps and Legislative Requirements

g.1 Can the PUC implement this proposal by itself, or is legislation required? What would the legislative requirement be?

The PUC can implement this proposal for PUC-jurisdictional entities but not for municipals and other entities not under CPUC jurisdiction. Legislation is required to extend this program to all retail and other end-use providers in the state, including municipals and other entities not under CPUC jurisdiction.

g.2 What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the Commission's 1998 implementation goal?

Whether implemented by the CPUC or state agency, implementation does require a series of steps, including: adoption of rules defining process of obtaining RECs for renewable generation; adoption of rules defining requirement for retail and other end-use providers; development of reporting, monitoring and tracking procedures; and adoption of a dispute resolution process. If implemented state-wide, legislation is required to both establish the requirements and designate the state agency responsible for administering the program.

The amount of time required depends on the extent to which parties are able to reach a consensus on implementation procedures. An estimate of 12 months seems reasonable given the need to develop specific rules, to allow sufficient time for parties to review proposed rules, and to notify market participants of adopted rules. Some of these MRPR activities may proceed in parallel with other restructuring activities but other MRPR activities will need to be closely coordinated with these other restructuring activities. For example, MRPR reporting rules governing regulated and unregulated retail and other end-use providers should be consistent and potentially utilize the same infrastructure developed for other reporting requirements for retail and other end-use providers.

4. Positions of the Parties in Favor/Neutral/Oppose

Comments of the CPUC's Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

DRA/UCAN/IPP oppose this proposal because:

1. The proposed cap of 2¢/kWh could result in a simulteneous implementation of RECs and a surcharge program. This is unnecessarily complex.

2. RECs for post-fixed-price QFs are tradable. To incentivize buyouts, they should not become tradeable until the contract is bought out.

3. Non-compliance fees can be booked in PBR. This would be unfair to competitors.

4. Non-compliance fees could be used to write down non-renewable CTC. They should support new renewables

5. UDCs are not required to pass through local T&D benefits distributed renewables owned by customers and competing providers.

6. Credits accrue to distributed renewables owned by UDCs or affiliates. UDC-owned distributed generation would conflict with key aspects of restructuring.

Comments of AWEA

OPPOSE. 2¢ fee undermines market for renewable energy credits because it's too close to the expected marginal cost. Encouraging payment of fees instead of compliance creates a pool of funds that must be publicly administered - contrary to the Commission's stated intent to avoid "prescribed allocation mechanism(s) or bidding procedure(s)." Year-2000 sunset undermines competition from new or repowered resources. Level of standard proposed under CPUC-only implementation too low to support existing level of renewables and does not support existing diversity from biomass resources. Proposed allocation of credits creates QF disadvantage in contract negotiations.

Comments of GEA

Concur with AWEA. The 2¢/kWh fee proposed will stifle the market for renewable energy credits because it's too close to the expected above-market cost of renewables. Encouraging payment of fees instead of compliance produces funds that must be publicly administered, but does nothing to preserve the renewables industry. Conversely, the 6¢/kWh penalty proposed by AWEA is high enough to virtually compel compliance. This 6¢ penalty cannot be multiplied by the number of kWh in the RPS to calculate a cost cap on the program, as is proven in the EPA and Haddad letters included in AWEA proposal.

Comments of CBEA

Concur with AWEA. The level of standard proposed under CPUC-only implementation is too low to support even close to the existing level of renewables. If increased to 13.3% of IOU sales of kWh it would support about 90% of existing renewables. The lack of biomass standard within the overall standard would effectively eliminate the biomass generators from competition with other renewables, forcing that industry out of business and taking with it its waste management, air quality, and forestry-related benefits. The proposed year-2000 sunset, absent legislation extending the standard to all electric providers statewide, undermines development of new or repowered resources.

Comments of STEA

Concur with AWEA. The proposed allocation of credits (to IOU for all QFs under contract) eliminates the possibility of a revenue stream to the QFs, the basic purpose of which is to make QFs viable in a restructured industry and retain their associated benefits. This allocation is intended to force QFs to negotiate out of their contracts with IOUs; any forced negotiation is inherently unfair. When this forced negotiation is combined with the proposed 2¢/kWh cap on credits, the QF is essentially forced to remain under contract, foregoing credits, and defeating the entire purpose of the minimum purchase requirement.

Comments of Some Surcharge/Production Credit Proposers

(Note: Where Surcharge/Production Credit Proposal supporters' names appear independently in these "Position of Parties" subsections, their position is not included in the following position statement made on behalf of the remaining supporters.)

Oppose:

1. Limits cost impacts to customers: Limits total customer cost exposure by incorporating a cost cap at 2 cents/kWh.

2. Encourages renewables competition and drive for efficiency more than other MRPR proposals: By not requiring rate bands, technologies are encouraged to develop methods to bring costs down to compete among market participants.

3. May meet CPUC decision requirements: This proposal was designed to conform with the specific details of the CPUC decision but may not reflect the preferred choice of its sponsors.

Comments of Orange County, Sonoma County, the City of Sacramento, NEO Corporation

We oppose this proposal because it ends in three years if the legislature does not act to make the program State wide. This is unfinanceable help. We oppose support for existing projects. SCE's inclusion of existing facilities who terminate Standard Offer Contracts is interesting. Nevertheless, it may solve a CTC problem at the expense of renewables. The idea of having the penalty for nonperformance act as a cap on the subsidy is excellent. It avoids cumbersome policing administration. However, we feel 2¢ is too low. We can probably support elements of this proposal when combined with the EDF proposal.

Comments of the Union of Concerned Scientists

Oppose.
Good points: Exclusion of hydro avoids subsidization of a mature, fully commercialized technology and problems with annual variability.
Bad points: Low 2 cent/kWh non-compliance charge, encourages non-compliance, turning competitive program into administrative program by creating non-compliance fund. Classification of non-compliance charge as business expense instead of a penalty allows for tax write-off, further decreases compliance incentive. Does not support renewables growth since MRPR does not increase. Does not adequately address issue that green marketers could double-dip by collecting RECs and charging more for energy. Will terminate in 2000 if not backed up by legislation.

Comments of Los Angeles Department of Water and Power (LADWP)

The procurement of renewable resources should be the responsibility of some state entity for the state power pool and the above-market costs of compliance should be borne uniformly by all customers served by the UDC on a non-bypassable basis. Rather than having many entities responsible for procurement of renewables, having one entity responsible for the state's procurement of renewable resources will minimize the transaction costs of compliance. The level and diversity of renewable resource mix should be established by the state legislature. The renewables program should be reviewed every five years or so.

Comments of Southern California Edison

This is the simplest of the MRPR proposals. It has no separate biomass standard. It is based on energy only and requires annual, not monthly accounting. Moreover, it has two key features that benefit electric customers.

It has an implicit cost cap of two cents per renewable kwh. Therefore no retail provider has to pay more than a two cent premium, for renewable energy.

Second, it assigns the value of renewable credits from standard offer contracts to ratepayers. This is equitable because ratepayers have already paid for these renewable projects through high priced, standard offer contracts. Projects that negotiate out of standard offer contracts can get the value of credits, however. This sets up an incentive for QFis to restructure their long term contracts.

Comments of CalSEIA/SEIA/ETDD

OPPOSE

Low Credit Ceiling Defeats Purpose: Like the RPS proposal, MRPR would not encourage diversity or new resources development because 2 cent limit is too low to finance new plants with emerging technologies. While 2 cent cap will limit MRPR cost, even for existing renewables, this cap should be raised or substantial portion of existing renewable generation will be uneconomic resulting in shortage of credits, resulting in credit values above cap value and state having to sell substantual numbers of credits. Who will collect fees, how fees will be collected and what the state collected fees will be used for need to be established. Potential program elimination in Year 2000 makes it impossible to finance new plant construction, even for established renewable technologies.

Comments of the California Integrated Waste Management Board

Qualified Support with more conditions: This proposal is similar to other MRPRs in its basic premise--all retail sellers must purchase a minimum amount of renewables.

The major concerns with the proposal are: (1) the the non-compliance penalty may be so low that there may be a financial incentive to not comply with the purchase requirement; (2) it allocates RECs to the UDCs for all renewable generators which are under Standard Offer contracts, including ones paid at SRAC; and (3) the pro-rata treatment of renewables tha use fossil fuels, such as biomass for start-up, may hurt certain generators and be very difficult to monitor.

Comments of Don Augenstein

The cost limit, effectively a “REC cap" of 2 cents/kWh appears quite possibly too low to maintain the current level of renewables. In addition certain renewables' (wood, biogas) environmental benefits are not recognized; the proposal does not support a solid fuel biomass band. The proposal omits mention of electricity from biogas (possibly unintentionally). That renewable energy source should certainly be included. These are the main reservations with the MRPR approach as advanced by SCE and PG&E. Otherwise this proposal appears reasonable.

Comments of SoCAL Gas

NEUTRAL - Of all the minimum renewables purchase requirement proposals, this is the simplest and most straight forward. The proposal excludes hydro, a simple target of 10% of all kWh sold to all California end users is proposed, it eschews specific technology bands, and it provides for the purchase of renewable credits at a nonpunitive 2 cents/kWh, which SCE interprets as an upper bound to the cost of the program. Most appealing is the clear realization that the program should be fully reviewed every five years and if not implemented statewide, the program should be cancelled.

Comments of SDG&E

Oppose:

- Unequal cost burden on consumers. Penalizes SDG&E's customers for not having previously been subjected to more high-priced ISO4s.
- Additional annual cost to San Diego customers estimated at $32 million based on a 2¢/kWh cap.
- Shifts costs from customers in one region to another, raising rates for some and violating the Commission's policy against cost-shifting.
- Inequitable for consuners because municipal customers pay no share of this proposal.
- Primarily subsidizes already-subsidized existing projects instead of new development.
- Inconsistent with electric restructuring; mandates distribution companies to maintain resource portfolio instead of relying on the competitive market.
- Administratively burdensome and complex.

Comments of IEP

- Proposal creates barriers for QFs to engage in contract restructuring because the value of all credits accrue to UDC.
- Represents a reduction in level of renewables attained through existing state policy.
- Policing and enforcement mechanisms to ensure compliance are unclear; relies on unnamed: state agency and may require formation of new state agency.
- Minimizes likelihood that renewable energy is actually produced as a result of the policy because (1) penalties for non-compliance are set too low (2 cents/kWh) and (2) sunsets program after only two years (absent legislation).
- Ignores existing legislation fostering renewables; requires new legislation to ensure program continuance.

Comments of the California Water Environment Association

1. RECs should be applied to energy and electricity generated from renewable sources and used onsite.

Reason: If cost for energy generated and used onsite is not competitive with market, a strong economic incentive to shut down this renewable energy and replace it with fossil fuel based energy may occur.

2. Add statement to exclude CTCs from electricity generated from renewables and used onsite.

Reason: The owner of above facility made a large investment in facility. The CTC recovers funds for power companies invested facilities. The CTC could prevent the renewables owner from recovering investment or being competitive.

Comments of PG&E

PG&E believes that all the RPS proposals, including our own proposal, may be basically incompatible with the increasingly competitive and disaggregated generation market. We therefore support a surcharge method. Nonetheless, we recognize that an RPS standard might be imposed. Thus, we joined with Edison to provide a variation which minimizes complexity, sets a reasonable generation target and expenditure cap, and provides for an early progress review.

E. All Renewable Credit Proposal

Submitted by: The Sacramento Municipal Utility District

1. Interpretation of Commission's Goals and Rationale for Strategy

In crafting their decision, the Commission recommended that the following points be considered:

- All utilities and their competitors must bear the cost of public purpose programs in order to avoid a legislated advantage to any single provider or class of providers.
- A target level of renewable generation seems to be the best solution in the short term.
- Renewable resources currently in operation include both utility owned renewables and resources that sell under QF contracts.
- Resource diversity is a valuable attribute and the Commission is committed to its preservation.
- Above market costs of existing renewables might be recovered under the QF transition cost recovery mechanism.
- Either the retail provider or the generator must be required to meet the target level of renewable generation.
- The required level of renewable generation must be specified as energy or capacity.

In preparing the ARC proposal, the following salient points were incorporated to implement the Commission's direction and concerns:

- The renewable resource portfolio standard must apply to all retail sellers, with no exceptions for self-generation or non-traditional providers.
- The requirement to preserve the current level of renewable resource generation at 21% of energy supply will continue the diversity that California currently enjoys.
- In addition to utility owned renewables and QF contracts, some utilities also purchase renewables from out of state suppliers. This adds diversity to the California system and should be rewarded with full credit for these renewable resources. Where current firm contracts for out of state hydroelectric resources exist, credit should be given. Where current firm contracts for other out of state renewables exist, credit should be given. For the purpose of establishing the currency of contracts, the end of 1995 should be used. By only recognizing contracts in continuous use from 1995 until the time of credit, existing resource no used to meet California load will not be allowed to supplant resource that currently add to the diversity of California energy supply.
- While above market costs of QF contracts might be recovered for prior or current year sales using the CTC, forward looking costs are difficult to predict and collect. Capping

above market costs of QF contracts with the CTC would infer that QF contracts would end at the end of the transition period. This could lead to a drastic reduction in the level of renewable diversity that California would enjoy in the future. The ARC proposal allows for the continuation of these resources using a market driven approach. Since the ARC proposal requires that the current level of diversity be continued, current resources could be utilized until they are replaced by more beneficial or less expensive renewable resource options.

- Energy provides the best measure of renewable resource contributions to diversity. Renewable resources are more likely to be used to their fullest potential as energy sources, not as capacity sources. Measuring renewable resource contributions to diversity as capacity distorts their place in utility planning. Energy production requirements will tend to encourage cost effective and efficient use of our renewable options. The ARC proposal uses energy to measure renewable resource requirements.

The ARC proposal provides full credit for the entire spectrum of renewable options with the added benefits that this diversity can deliver. The exclusion of existing hydroelectric resources from the credit market compensates for the possible exclusion of more diverse renewables by hydroelectric resources.

The ARC proposal would not violate any interstate commerce provisions since the location of the renewables is not requisite to inclusion in the program or in establishing eligibility for credit trading. The only requirement used for establishing eligibility of a renewable resource for program inclusion requires that hydroelectric resources must have either supplied energy by continuous contract into the California energy mix prior to December 20, 1995, or be placed in service after December 20, 1995. Hydroelectric resources that were in existence, but not supplying the California market prior to December 20, 1995, would not be eligible for inclusion in the program. This does not refer to where the resources are located, but instead focuses on the Commission's intent to continue the level of diversity currently in place in meeting California's energy needs. Hydroelectric resources not contributing to this diversity in 1995 would not be eligible to participate in the program. An additional requirement for credit trading disallows credit trading of any hydroelectric resource in existence on December 20, 1995. Again, the location of the resource is not required or specified. Only hydroelectric resources placed into service after December 20, 1995, are eligible for credit trading.

2. Program Overview and Description

a. Renewable Portfolio Standard Guidelines

- The Renewable Portfolio Standard should be applied to all market participants serving retail load in California.

- At a minimum, the current level of renewable energy use in California should be preserved.
- Local control and decision making over the amount, type and timing of renewable resources should continue.
- Alternatives for development of renewable resources need to be made available to market participants unwilling or unable to finance and develop renewable resources as part of their resource mix. Alternatives may include payment into a fund to be used by an administrative agency to develop appropriate renewables and establishment of a vigorous market for renewable "credits" to allow trading of renewables among market participants.
- Participation in the Renewable Portfolio Standard should be made mandatory for all market participants through appropriate legislation.

b. Application

The Renewable Portfolio Standard will be applied to all distribution utilities and other retail sellers in California. All retail sellers, including municipal utilities, electrical cooperatives, cities, state agencies, and new direct sales entities should be required to track and report to an appropriate state agency the amount of sales and the sources of generation or purchases necessary to meet their needs.

c. Preservation of Renewable Resources

The existing resource portfolio in California is the result of tremendous effort by the California utilities, the California Public Utilities Commission, the California Energy Commission, and independent energy providers. Based on energy used, produced, bought, and sold in 1994, this diverse resource portfolio contains roughly twenty-one percent (21%) renewables,. The estimates have been corrected to approximate an average water year for hydroelectric energy production. We believe that this is an appropriate and sustainable minimum level of renewables for the State of California.

Existing renewable resources currently being used to serve the State's electric customers should receive full credit under the new Renewable Portfolio Standard. This includes hydroelectric, geothermal, solar, wind, waste-to-energy, and biomass energy sources within the State. These resources have been providing fuel diversity and environmental benefits to California residents. Allowing them to receive full credit will insure that market participants who own such facilities will receive the proper incentive to continue to cultivate and husband such renewable energy sources.

d. Renewable Credits Trading

In the event that a market participant is unable or unwilling to finance and develop renewable resources, alternatives need to be made available to assure their participation. One alternative includes establishment of a renewable trading market. Under this alternative, market participants with renewable energy credits in excess of their needs could make the credits available to other participants in a renewable credits exchange.

An independent entity, such as the proposed power exchange, would facilitate the trading of renewable energy credits and verify that the renewable generation records are accurate. The power exchange or facilitator would issue credits for renewable energy generated. It will sell those credits at a market clearing price to retail entities in need. Renewable generators would receive those revenues in relation to their credits. Since the power exchange will be acting as a market facilitator for much of the bulk power market on a daily basis, facilitating trades for renewables should be a natural extension. Of course, market participants are free to use the exchange or avoid its use and develop specific bilateral contracts.

Such a trading environment will allow local distribution entities to determine the amount, type and timing of renewable resources in its service territory. If a specific distribution company wants to promote a specific type of renewables, it can do so and sell any excess into the credit trading market. Alternatively, a retail entity can purchase all its credits from the market.

All renewables, with the exception of existing hydro power, would be eligible for trading credits, regardless of location. The reason for excluding existing hydroelectric energy resources from such a "renewable credit exchange" is to ensure that a viable and vigorous trading market develops. Including existing hydro energy from plants that were built decades ago, and that have been largely depreciated, in this market would likely distort the incremental price for new renewables and would not send the proper price signal for new investment in renewables to developers and other market participants.

New hydroelectric resources not in existence on December 20, 1995 could be included in this market. Such resources are often developed from improving the efficiency of or upgrading existing resources. Using the existing water more efficiently should be encouraged and allowed to trade in this new market.

e. Example

If a retail seller had sales of 1,000,000 kilowatt hours in one year, they would be required to have generated or purchased 210,000 kilowatt hours using renewable resources to meet the Renewable Portfolio Standard. If they did not meet this requirement, they could purchase credits from a California local distribution utility or other retail seller that had more than 21% of their sales from renewable resources. Credit transactions would not actually result in kilowatt hours delivered to the retail seller needing the credits. Credit trades would result in a monetary exchange for the right to use the credits. This would preclude the seller from taking credit for the renewable generation in meeting their own Renewable Portfolio Standard requirements.

Renewable credit transactions would be facilitated and regulated by an independent facilitator. Retail sellers and local distribution utilities would be required to meet the Renewable Portfolio Standard on a yearly basis, with on-going reporting and reconciliation to handle hydrological swings. The trading period and the requirement period could be any duration from one month to one year, depending upon the needs of the seller and the buyer. A market clearing price would be determined at the end of each trading period and recorded by the independent facilitator.

f. State Administered Fund

A second alternative would include an option for the market participant to pay into a fund administered by a state agency responsible for developing and financing renewable resources. Since a market clearing price for renewable resource credits may be established under the exchange mechanism, the payment would equal the clearing price from the exchange. Until the exchange becomes active, the price could be set administratively set at the projected lowest incremental cost of new renewables with a true-up to reflect the actual price once the renewable credit exchange is in full swing.

3. Implementation Questions

a. What is the Obligation?

a.1. How is "renewables generation" defined for purposes of qualifying for tradable "renewable energy credits" (REC's) under this proposed program? Are existing and incremental utility-owned renewables included?

Our proposal qualifies all non-hydro renewables and all hydro built after December of 1995 for credits. The definition of renewables is not given in our proposal, but the definition that SMUD used for our Request for Proposals for Renewables requires an essentially unlimited source of energy replenished by natural and human actions, with the reserves of energy essentially unchanged for the life of the contract. Existing utility owned renewables receive credit and can be traded, except existing hydro. Existing hydro receives credit, but cannot be traded.

a.2. What are renewable energy credits? How do they relate to energy portfolio management?

Renewable energy credits are traded to make up for a failure to generate sufficient energy to meet the renewable portfolio standard of 21% (all renewables).

a.3. How are a diversity of renewables encouraged?

Limiting credits to renewables plus new hydro tends to encourage diversity.

a.4. Are currently high-cost technologies or pre-commercial technologies fostered by this program?

The market would tend to move toward the least expensive new projects over time. As technology costs decreased, technologies would earn more market share. RD&D funding could continue the sustained orderly development of more costly or pre-commercial technologies.

a.5. How is renewable self-generation handled? Is self-generated renewable energy eligible for Renewable Energy Credits, or for other means of support?

If the independent system operator is required to monitor all generation and all loads, self generation will be monitored adequately to allow calculation of the renewable resource percentage of that generation source. If the exchange monitors self generation, the exchange could facilitate the purchase of renewable credits if a self generator needed them to comply with the renewable portfolio standard. In this model, the only scenario that would make self-generation exempt from the renewable portfolio standard would be complete disconnection from the system, and even that scenario could result in the requirement to comply if the legislation was worded properly. We would encourage carefully crafted legislation that ensures the renewable portfolio standard is not bypassable in any instance.

Renewable self-generators are not precluded from selling their credits, so this might result in additional benefits from renewable self-generation if the credits were not needed by the self generating entity.

a.6. How are hybrid fossil-fuel/renewable facilities handled?

Fossil fuel is not allowed to receive renewable credit. Hybrids can receive credit for the renewable portion only.

a.7. Does out-of-state generation qualify for Renewable Energy Credits? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

All renewables would qualify.

a.8. If hydro is included, how are practical issues associated with hydropower handled?

Year to year fluctuations would result in year to year variance in energy generation. This would have to be reported. A very dry year might result in a distribution utility needing to purchase additional credits from non-hydro renewables. We suggest using the period of record to determine average hydro production and record keeping to ensure long-term compliance. Only new hydroelectric facilities would be eligible for trading.

The option to pay into the renewable development fund would provide an alternative in the event sufficient renewables were not available for purchase.

a.9. How is utility-owned generation of distributed renewables handled? Is it eligible to receive RECs or surcharge funds? Does the proposal permit or prohibit Renewable Energy Credits from being awarded to distributed utility-owned renewable power not sold through the Power Exchange? Does the proposal permit RECs or surcharge funds to accrue to distributed or other renewable applications that may involve the cross-subsidization of generation with T&D savings, or vice-versa?

The ARC proposal assumes that all generation is tracked by the exchange, even distributed generation. All renewable generation would qualify, subject to the exclusion of existing hydroelectric resources from credit trading discussed above.

a.10. What is the level for the requirement? How does this level relate to the level of renewables form 1990 to the present? Does the level of the requirement increase over time, and if so, at what rate?

The level is set at 21% of energy sales, based on the 1994 statewide level of renewables.

a.11. Describe how, if at all, the compliance obligation adjusts during a transition period.

The level stays at 21% of energy sales. As sales increase, the amount increases.

a.12. Does the proposal include a uniform requirement for all electric providers, including utilities, on a state-wide basis?

All retail sellers of electricity are subject to the renewable portfolio standard.

a.13. What is the time-horizon for the program?

No sunset date was proposed.

a.14. Is the requirement established on a percentage of Megawatts of percentage of Megawatt-hours basis?

The requirement is based on energy sales in kilowatt hours.

a.15. Does the proposal establish floors for certain technology types? What is the rationale for a technology floor, if proposed?

There are no minimums proposed. The local control built into our proposal would allow the various generators to pick the technology best suited to their situation and their locale.

b Where is the Obligation to Comply?

b.1. On whom is the requirement applied? Is the requirement applied only to entities under the Commission's jurisdiction, or is it applied state-wide?

Retail sellers. All retail sellers, selling power in California.

b.2. Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences?

No difference.

b.3. What is the penalty for non-compliance? Should this penalty be interpreted as a cost-cap for the program?

Penalties are not addressed specifically, but we do propose a statewide fund for entities not purchasing credits

b.4. How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

An independent facilitator or the exchange operator would track compliance.

b.5. What provisions add flexibility in compliance?

The attribute of local control over the resources chosen would tend to facilitate flexibility.

b.6. How does the program ensure that the policy and its costs are non-bypassable, such as the CTC or the Public Goods surcharge?

Legislation would help ensure compliance.

c. How are Renewable Energy Credits Initially Allocated?

c.1. How are Renewable Energy Credits generated from existing renewable facilities (QFs and utility-owned) initially allocated? What impact does the initial allocation have on whether a vigorous market for Renewable Energy Credits, characterized by many buyers and sellers, forms?

Credit would be given to the retail seller that buys the power from the source, through marketers, aggregators, or directly from the IPP, or through the exchange.

c.2. What is the relationship of the allocation of renewable energy credits and the CTC or Public Goods surcharge? Will RECs accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid and avoid the CTC?

Since the independent system operator would track energy usage because of their need to track ancillary service, only customers totally disconnecting from the system would bypass CTC and renewable standard. Even those customers might be compelled to comply if the legislation were applicable to disconnected customers as well. Customers would not be encouraged to disconnect from the grid by the renewable portfolio standard.

c.3. If customers or ratepayers are initially allocated Renewable Energy Credits, how are the credits administered?

Customers are not allocated credits.

c.4. What, if any, is the relationship between the proposed allocation of Renewable Energy Credits and the status of existing QF contracts?

The contracts that continue would allow the purchaser of energy from the renewable resource contract to get the credit.

c.5. How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

Not addressed specifically, but the CTC calculation should address this to the extent a utility owns (or contractually receives) the resource.

c.6. Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

Not addressed specifically, but the CTC will capture this value and likely lower the overall transition charges to customers and therefore there should be no overall increase in value.

d. How is the Program Administered?

d.1. What agency certifies Renewable Energy Credits?

Not specified.

d.2. What mechanisms are proposed for trading of Renewable Energy Credits? How do the trading mechanisms relate to the initial allocation of Renewable Energy Credits?

Not addressed.

d.3. What mechanisms are proposed for program oversight and mid-course corrections?

Not addressed.

d.4. What agency monitors and enforces compliance with the program, and how is it carried out?

Not specified.

e. Cost-Related Issues

e.1. What are the costs associated with the program, and who pays?

Administrative and oversight costs must be borne by the retail sellers.

e.2. What cost-containment measures, if any, are provided?

The use of a market for renewable credits increases competition and thereby keeps costs down *e.3. If the program utilizes floors for certain technology-types, what are the implications in terms of costs and benefits?*

No floors are used.

e.4. Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

No.

e.5. How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities encouraged?

Using an open market.

e.6. What implications, if any, does the proposal have in defining the roles of the LDC and of competitive suppliers of electricity?

The LDC would most likely be the retail seller, responsible for meeting the renewable portfolio standard.

e.7. What is the consistency of this general proposal in relation to cost-related guidance provided by the PUC road map?

The current level of renewables is used as the target for future resource portfolios.

f. How does the Program Fit with Other Aspects of Electric Industry Reform?

f.1. Is the Program compatible with the existence of an Independent System Operator? A Power Exchange? A Direct Access Market? Is the proposal consistent with the Commission's view of the role of the Power Exchange and ISO?

The program is compatible with the existence of an independent system operator, a power exchange, a direct access market, and the Commission's view of their various roles.

f.2. Is the proposal dependent in any way on the Power Exchange or ISO? If so, are there any additional protocols necessary?

The power exchange could facilitate sales but must track the buyer and the seller and the technology if renewable.

f.3. Does the proposal involve conflicts of interest between distribution and competitive retail service? If so, how are they resolved?

No.

f.4. How does the program avoid conflicts of jurisdiction between state and federal levels?

This would be a State mandated program.

f.5. What is the relationship between the Proposal and Direct Access "Green Marketing?"

Green marketing might result in "selling the same kWh twice" since a green marketer would be likely to have excess credits to sell. If someone can sell a kWh as green power they can reduce the cost they would ask for the credits and therefore reduce the cost of tradable renewable credits.

f.6. What is the relationship between the proposal and Performance-Based Ratemaking? Does the proposal place Renewable Energy Credits under PBR, or exclude Renewable Energy Credits from PBR?

Renewable Energy Credits do not require or affect PBR.

f.7. Does the program create any potential market power problems involving the generation market or Renewable Energy Credits?

Our proposal keeps existing hydro out of the trading market to avoid market power issues.

f.8. How does the proposal relate to any consumer protection of consumer education efforts? For example:

a) Rules for New Entrants. Does the proposal entail any licensing requirements for new entrants? Should compliance with the minimum renewables requirement be a condition of selling power at the retail level?

Yes, all retail sellers are required to maintain the 21% renewables standard.

b) Consumer Education. Does the proposal require any consumer education? For example, how does the proposal protect customers from "green marketing" programs where marketers collect twice--once for credit sales and once for "green" power sales, thereby not increasing total green power? This could entail, e.g., amount of renewable energy they are *purchasing that are supports by RECs, or statements regarding price stability of price risks associated with the seller's resource portfolio. Would RECs accrue to utilities from green pricing programs where utilities have unique customer information and access?*

The artifact of "selling the same kWh twice" might actually be a benefit, since it would encourage a sustained orderly development of renewables, and increase incentives to build new resources.

f.9. How, if at all, does the proposal relate to RD&D programs funded by the Public Goods Charge?

No relationship.

f.10. How, if at all, does the proposal relate to the energy efficiency programs funded by the Public Goods Charge?

No relationship.

f.11. How does this proposal affect the CEQA compliance work recently initiated by the CPUC?

Unknown.

g. Legislative Requirements

g.1. Can the PUC implement this proposal by itself, or is legislation required? What would the legislative requirement be? What is the status of entities not under PUC jurisdiction in this program?

Legislation is required. All retail sellers would be affected. The legislation should include self generators and disconnected customers.

g.2. What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the Commission's 1998 implementation goal?

Legislation would be required.

4. Positions of the Parties in Favor/Neutral/Oppose

Comments of the CPUC's Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

DRA/UCAN/IPP oppose this proposal because:

1. At 21 %, the proposed portfolio standard is too high. It would have inequitable impacts on some retail providers. This high percentage is due to the inclusion of hydro in the standard in the form of non-tradeable credits.

2. The simultaneous implementation of a credits program, credits exchange and surcharge fund is unnecessarily complex.

3. The proposal does not rule out credits accruing to UDC-owned distributed renewables.

Comments of AWEA

OPPOSE. Compliance with the 21% renewables requirement established under this proposal would be virtually impossible for retail sellers that do not already possess or control substantial hydro resources because hydro credits are not tradable. Thus, the price for renewable energy credits would be so high that retailers would choose to pay the penalty instead of complying, defeating the purpose of the portfolio standard. Seasonal and annual fluctuation of hydro generation would make compliance difficult to impossible for all retail sellers. Proposal does not address problem of cross-subsidy of other non-electric features of hydro power.

Comments of CBEA

Concur with AWEA. Inclusion of hydro resources in the standard invites "rerouting" of Northwest hydro energy into the California market, defeating the purpose of the portfolio standard, which is maintaining the existing level and diversity of California renewables. Inclusion of hydro brings probably insoluble problems of dealing with wet vs. dry year variations and with out-of-state resources, since hydro is by far the most likely out-of-state renewable to pose a significant competitive threat to California's renewables. Hydro generation is a fully mature technology, and is competitive with non-renewable generation; it should not be included in a portfolio standard.

Comments of Some Surcharge/Production Credit Proposers

(Note: Where Surcharge/Production Credit Proposal supporters' names appear independently in these "Position of Parties" subsections, their position is not included in the following position statement made on behalf of the remaining supporters.)

Oppose:

1. Increases the MRPR by nearly 100% (to 21% of total supply) over other proposals: Includes existing hydro in the calculation of an "appropriate and sustainable minimum level of renewables" (roughly 21%). However, the proposal excludes existing hydro projects in its definition of renewables eligible for funding. Non-hydro existing renewables account for around 10% of current electric supply. Hence, this proposed minimum purchase requirement would double the level of electric supply currently provided by existing renewables eligible for funding.

2. Creates both an MRPR and a renewables surcharge-type fund: Double funding mechanisms requires doubling the administrative oversight/review burden for the state.

3. Fails to define costs: The proposal has no cost cap.

Comments of Orange County, Sonoma County, NEO Corporation

We oppose including hydroelectric resources because they are proven renewable technology with a century of experience. Even though this program gives hydro REC's without trading value, it takes REC's out of circulation without stimulating new projects. Also, we oppose this proposal because it continues to subsidize existing facilities. Competition should be market driven through an unencumbered bid process. The idea of having REC trading connected with WEPEX is an interesting concept that should be considered.

Comments of the Union of Concerned Scientists

Oppose.
Cons: Inclusion of hydro subsidizes mature, fully commercialized technology and causes problems with annual variability, while doubling cost of compliance for same non-hydro renewables goal. Non-tradability of RECs from existing hydro will cause guaranteed non-compliance by some utilities due to shortage of available RECs, turning competitive program into administrative program by creating penalty fund. Green marketers would be able to double-dip by collecting RECs and charging more for energy.

Comments of Los Angeles Department of Water and Power (LADWP)

DWP favors the continued support of renewable resources, however, it should be made clear to reviewers of this report that SMUDis proposal does not represent the position of all municipal utilities. The level and diversity of Californiais renewable resource mix should be established by the state legislature and the above-market cost for supporting renewable generation should be uniform throughout the state. The procurement of renewable resources should be the responsibility of some state entity for the state power pool and the cost of compliance should be borne by all customers served by the UDC on a non-bypassable basis.

Comments of CalSEIA/SEIA/ETDD

OPPOSE

Hydro Variability Creates Unstable Market: California hydro generation may average 10% but annual variability ranges from 5-15% of total consumption. Inclusion of hydro creates requirement that no utility can meet in a dry year, since it means at lest 50% short-term increase in non-hydro RECs to cover hydro shortfall. Problem is that REC providers cannot increase supply this quickly, nor for just a short period. To build new renewables requires long-terrn, stable markets for RECs. Proposed state administered fund would be essential to cover dry year shortfall, but price of payments is undear and use of funds is unspecified.

Diversity and Emerging Technologies: Low credit prices and substantial inter-year price variability due to hydro make developing and financing any new renewable generation, especially emerging technologies, unlikely.

Comments of the California Integrated Waste Management Board

Oppose: The primary objection to the SMUD proposal is the inclusion of hydro as a eligible renewable resource. As with the NCPA proposal, the inclusion of hydro could force the more classic renewable technologies out of the marketplace.

SMUD mitigates some of the impact of hydro by not allowing the trading of credits that would be based on hydroelectric power.

SMUD has not addressed the issues of enforcement and compliance.

Comments of Don Augenstein

The SMUD proposal presents its strategy with less detail than other proposals. It appears by and large reasonable. As with NCPA, it does not address how the serious questions associated with inclusion of hydro will be resolved.

Comments of SoCAL Gas

OPPOSE - This proposal stresses local control of the amount, type, and timing of renewable resources. Including hydro (adjusted to an average water year) as a renewable resource raises the target percent of kWh from renewables to 21%. Including hydro leads to complications. Hydro swings can be quite large and unpredictable, leading to large purchases of renewable credits in dry years. Excluding existing hydro from the renewables credit market is discriminatory. Utilities with access to hydro will have a large advantage over utilities that do not have the same access. No mention is made of the cost or length of the program.

Comments of Southern California Edison

This proposal has some positive aspects. It does not have a costly technology band for biomass and it applies statewide to all retail providers, including public utilities.

Inclusion of hydro is problematic. While hydro generation does not contribute to air emissions, there are other environmental impacts to be addressed. Because hydro credits are not tradeable, the high standard of 21% will be expensive, if not impossible, to meet for many retail providers. Finally, including hydro increases complexity associated with the treatment of wet and dry year variations and out-of-state resources.

Comments of SDG&E

Oppose:

- No cost limitation. Potential cost to SDG&E's ratepayers exceeds $67 million assuming a 2¢/kWh REC cost.
- Unequal cost burden on consurners.
- Primarily subsidizes already-subsidized existing projects instead of new development.
- Envisions Power Exchange as facilitator of tradable renewable credits, creating more operational complexities for the Exchange.
- If the Power Exchange is the administrator, both legislation and FERC approval would be required, further complicating and slowing implementation.
- Administratively burdensome and complex.

Comments of PG&E

PG&E believes that all the RPS proposals may be basically incompatible with the increasingly competitive generation market. Should an RPS proposal nonetheless be imposed, PG&E believes SMUD's proposal deserves further consideration and development. It is designed to recognize the value of hydroelectric generation without discouraging future investment in non-hydro renewable resources. Additionally, SMUD's concept that the ISO could help in imposing this requirement might deserve further thought. While that would certainly be a complex and burdensome extra task for the ISO, the ISO may be in a better position than suppliers to track generation sources hour by hour.

4.2 Surcharge-Funded Production Credit Proposal

Proposal Submitted by: Environmental Defense Fund, Cambrian Energy Development LLC, Genesis Energy Systems, Laidlaw Gas Recovery Systems, Landfill Energy Systems, Los Angeles Sanitation Districts, NEO Corp., Orange County, City of Sacramento, Sonoma County, San Diego Gas & Electric, Pacific Gas and Electric, Southern California Edison, Solid Waste Association of North America

1. Interpretation Of Commission's Goals And Rationale For Strategy

In D. 95-12-063 the Commission stated:

> "We are committed to establishing restructuring policies which maintain California's resource diversity for existing resources as well as encourage development of new renewable resources." (p. 147)
>
> "We continue to believe that a minimum renewables purchase requirement is the best approach to meet our resource diversity goals......We have not concluded at this time on whom this obligation should be placed. We hope that the Working Group will provide us with further guidance on this, and will address this question further as we implement this decision....We prefer that the requirement be set at the same level for all electric utilities on a statewide basis, but recognize that it may be appropriate to develop a transitional strategy given the current resource portfolios of some utilities....We would expect that these minimum renewables levels would be in place beginning in 1998 and continuing through 2000, at which point we would revisit whether the requirement should be modified." (p. 150)

In summary the sponsors believe this Proposal meets the Commission's objectives because the Proposal:

- Sets a statewide funding level to be allocated for continued renewable development
- Can be implemented by 1/1/98
- Assures that new state-of-the-art technologies will be developed
- Sets an overall cost cap for the program
- Relies on a simple to administer auction process to allocate production credits to the most cost-effective projects
- Promotes a broad range of technologies
- Does not require penalties to assure implementation

- Would not provide a subsidy in addition to the prices QF projects receive under SO#2 or SO#4 contracts.
- Provides for administration of the program by an independent State agency already familiar with funding independent projects
- Would not result in any inconsistent obligations being placed upon investor-owned utilities which would be in conflict with the goals of a restructured electric industry
- Promotes renewable participation in the market mechanisms envisioned by the Commission - Power Exchange, contracts for differences, bilateral contracts

The sponsors offer this Proposal for consideration by the Commission as a method to accomplish the Commission's objectives and to do so in an effective, cost-quantified, and fair manner.

This program will be effective. It is consistent with restructured electricity markets that replace mandates with customer preferences and market incentives. The production credit for new projects supports only successful projects, while the 10-year term allows long-term financing. Since production credits, once awarded, are assured, this program can effectively promote renewable projects from its inception, even under the uncertainty of near-term review.

This program will quantify costs. Cost considerations have been a crucial element of the Commission's policy decisions on electric restructuring to date. The cost of this Proposal is neither open-ended nor uncertain. Total costs are subject to a certain cap. Renewables-on-renewables competition ensures that only the most cost-effective projects are supported. In addition, customer preferences for renewables and their attributes, such as their value as a hedge against fuel price increases, will serve to reduce the cost of this program.

This program will be fair. The costs of this Proposal are borne equitably by the State's electricity consumers and as such consumers in different service territories will not have to pay different amounts in order to fund the renewables program. This Proposal targets the cost of developing renewable generating projects in a manner designed to promote financability and development of these facilities. This Proposal does not heavily favor existing projects over new projects.

This Proposal does not require extensive monitoring or penalties for non-compliance. The Proposal is consistent with the separation of utility procurement and distribution functions. The sponsors believe this Proposal is unlikely to result in substantial litigation.

This Proposal has been developed specifically to avoid administrative complexity. In addition, it removes responsibility for implementation and administration from the investor-owned utilities.

The sponsors believe that any Proposal adopted by the Commission should foster consistent goals among parties. Continued renewable development is an important statewide goal, and to effectively accomplish this goal any mandated program should not place parties in conflict with the intent of or market functions envisioned for electric industry restructuring. Any program must also foster voluntary cooperation of the parties, rather than forcing compliance through arbitrary penalties or mandates. The sponsors urge the Commission to consider adopting this Proposal as the method for continued renewable development in the State.

2. Program Overview And Description

I. Funds Collected Via Nonbypassable Surcharge

a. Funding

- Program applicability and surcharges should apply to all end users on a uniform basis and requires Legislative action to implement on statewide basis.
- Any legislation to effect this program:
  - Must be uniform statewide surcharge
  - Must identify and cap the cost for the renewables program
  - Must provide for periodic review of process and need for continued funding
- Amendments to current legislative bills can be crafted or a new bill can be drafted to meet the objectives of Proposal. AB 1123 (Sher) is an example of a proposed Bill which can be crafted to accommodate this process. As currently drafted, AB 1123 would set a maximum of 3.3 % for energy efficiency, RD&D, and renewables (low-income services are outside this constraint).
- If legislation is not signed into law prior to 1/1/98, a two-phase process could be implemented. Initially surcharges could apply only to CPUC jurisdictional entities, until Legislative action expands authority for surcharge collection to all providers in the state; however, legislative action should be strongly pursued to implement the program statewide effective 1/1/98.

b. Applicability of surcharge and implementation

- Funds collected through statewide nonbypassable surcharge on all end users.
- A fixed dollar amount collected through the surcharge.
- The program will be administered by a State agency <u>not</u> by retail sellers. (e.g. California Alternative Energy and Advanced Transportation Financing Authority or other State agency as deemed appropriate).
- The actual amount of renewables development will be dependent on the cost-effectiveness of renewables compared to the market.

c. Review of Program

- The Proposal is intended for implementation over a five year period. The program should be reviewed in the year 2000 as envisioned in D. 95-12-063.

II. Funds distributed as per-kWh production credit

a. Allows renewables to compete in the market

- The Production Credit provided for a 10-year term.
- Funds are paid based on how much the developer believes it requires above the market price in order to make its project commercially viable. (e.g.: If the developer believes the market price for its project is 4 cents/kWh, but it requires 5.5 cents/kWh, then it would require a production credit of 1.5 cents/kWh to allow it to compete.)
- Renewable generation projects, limited to wind, solar (including solar thermal electric and photovoltaic), biomass (including solid waste biomass, solid waste-to-energy facilities, landfill gas, anaerobic digester gas), and geothermal, may qualify, subject to the following:
    - Production credits apply only to energy sold (not off-grid or on-site usage)
    - Applies to new projects or new additions to existing projects provided such new capacity is not available for sale under Standard Offer contracts
    - The production credit applies only to developers selling into the California market
- No project or technology will be prevented from seeking and using additional funds from grants, state or federal tax credits or industry financial or material participation.
- RD&D projects should be funded separately from renewables projects. It is recommended that the agencies which will administer the renewables and RD&D programs coordinate to establish principles for funding of projects that wish to participate in funding from both agencies.

b. Production Credits paid only to successful projects

- The surcharge funds are paid only when and to the extent that projects actually generate electricity.

c. Limited to new projects

- Production Credits are available for: (1) new renewable projects which begin operation on or after December 20, 1995; and (2) existing projects to the extent that (a) existing projects add new capacity (applicable to additional energy resulting from such addition) or (b) existing projects replace existing generation technology with new generation technology (applicable to the portion of energy resulting from replaced generation) and (c) no energy or capacity resulting from the new or replaced facilities are subject for sale under a standard offer contract.

III. Production credit level determined in periodic auction

a. Simple auction process

- Following are the principal rules that should be used to allocate funds. The State Agency should ultimately have discretion on the details of implementation of the program.
  - Simple auction. Developer bids ¢/kWh amount needed to allow project to compete in market and the expected annual kWh production level as the sole parameters
    - Single price bid for entire 10-year term of Production Credit
    - Single annual production level bid for entire 10-year term of Production Credit
  - Production Credit payments not to exceed annual production level bid
  - Payments only for energy produced/sold
  - Developer makes its own decisions and arrangements on marketing of its output
  - Must bid for 10-year term
  - Hybrid renewable projects eligible for production credits only for renewable portion of kWh production
  - No penalties necessary
  - No forecasts of market price or other factors necessary
  - Unused Production Credits distributed back into state fund, re-awarded as part of next auction
  - No pre-condition that bidder have a contract for sale of its power in order to participate in the Renewables Program
- This Proposal can easily accommodate emerging technologies.

b. A State agency should administer the program

- A State agency should administer this program. This Proposal identifies the California Alternative Energy and Advanced Transportation Financing Authority as an agency that has prior experience with administering funds for QF-related programs. Alternately, another state agency could be chosen to carry out the administrative functions of this program.
- IOUs/retail sellers, however, should not be obligated to administer the program. After restructuring, the IOU distribution companies will no longer be responsible for power procurement. Placing a mandate for procurement of renewables on the IOUs would be inconsistent with market functions post restructuring.
- Funds collected will not be required to be grossed-up since the surcharge will not be considered taxable so long as the funds are passed to the State for distribution.

- State administration of this program will eliminate potential conflicts and regulatory monitoring otherwise necessary to accommodate utility subsidiary projects which may seek funding under this program.

3. Implementation Questions

a. What Is The Obligation?

a.1 How is "renewables generation" defined for purposes of qualifying for tradable "renewable energy credits" under this proposed program? Do existing and incremental utility-owned renewable-resource generation qualify for Renewable Energy Credits?

The surcharge-funded production credit program does not involve tradable renewable energy credits; in the case of this proposal "renewables generation" must be similarly defined in order to determine those projects eligible for surcharge funds. The same definition adopted in the Renewables Portfolio Standard proposal is proposed here: biomass (including solid waste biomass, solid waste-to-energy facilities, landfill gas, and anaerobic digester gas); geothermal; solar (including solar thermal electric and photovoltaics); and wind.

Only energy-producing facilities that are not under contract or under cost-based or PBR-type regulation would be eligible to receive production credits.[15] In addition, eligibility should be limited so that only new projects or existing projects that have made significant new capital investments can qualify for production credits.

There are two principal reasons for limiting renewable development supported by the public goods charge to projects not under contract or regulation. First, projects under contract in many cases already receive above-market support for their production. Second, past ratepayer support of contracts for renewable projects was based in part on the assumption that the beneifts of those contracts – both direct (energy and capacity) and indirect (e.g., avoided pollution) – would continue over the life of the contracts without additional support.

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15 An exception may be made for facilities which are largely dediciated to non-energy purposes, such as distributed renewable generation. The primary value of distributed renewable generation may be in serving distribution functions such as substituting for substation or distribution investments. There are important issues related to unbundling of utility functions – such as self-dealing and cross-subsidization – that the Commission must address before such an exception can be made.

In addition, there are two principal reasons for limiting eligibility to new projects or existing projects that have made significant new capital investments. First, an emphasis of this proposal – in addition to recognizing public benefits such as the pollution avoided by renewable energy generation – is to advance the development of renewable energy technology. Second, if existing projects under contract could obtain public goods funding by leaving existing contracts, then this would have the effect of subsidizing contract buy-outs with public goods funding. Above-market contracts for existing projects are analogous to any other stranded investment. Such stranded investments should be addressed through CTC mechanisms rather than through public goods charges.

Out-of-state renewable facilities would be eligible to receive production credits, provided that their energy output is delivered to end-users who contribute surcharge funds. It is believed that this feature is necessary and sufficient in order for this proposal to comply with the "Commerce Clause" (see the response to question a.7).

This proposal also calls for the surcharge to be implemented on a statewide basis, in which case a project that delivers kilowatt-hours to the California market would be eligible for production credits.[16] If legislation is not enacted by 1/1/98 this proposal should be implemented by the Commission for CPUC-jurisdictional end-users. In this first phase, the nonbypassable surcharge to support renewables would be applied to CPUC-jurisdictional end-users, and renewable facilities would be eligible to receive production credits if their energy was delivered to CPUC-jurisdictional end-users. Legislation could extend the nonbypassable surcharge to support renewables to all California grid-connected end-users. In this second phase, renewable facilities would be eligible to receive production credits if their energy was delivered to any California end-user.

Since it may be difficult to trace kilowatt-hour transactions through multiple intermediaries, this proposal suggests a simple rule: kilowatt-hours will be eligible to receive production credits if they are sold to the Power Exchange (or ISO, which may make ancillary service purchases), or if they are sold via bilateral contract to a retail supplier that supplies only CPUC-jurisdictional end-users (in the first phase), or to all California end-users (in the second phase). Kilowatt-hours that are otherwise sold to CPUC-jurisdictional or California end-users may be eligible for credits, but the burden of proof will fall on the renewable supplier to show what fraction of its kilowatt-hours are provided for the benefit of these end-users.

a.2 What are renewable energy credits? How do they relate to energy portfolio management?

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[16] Rather than "delivered to," it would probably be more correct to say "provided for the benefit of" or "paid for by." The conventional usage of "delivered" is assumed to reflect these physical and financial realities.

NA.

a.3 How is a diversity of renewables encouraged?

This proposal does not make any specific provisions to encourage a diversity of renewable technologies. It does contemplate support for "emerging" technologies by specifying a separate production credit level (determined by a separate bid process) for such technologies. Constraints that would encourage diversity among renewable types (for example, set-asides that would allocate specific portions of surcharge funds to specific technologies) would tend to increase costs both by allocating funds to some resources which are not the least-cost resources across available technologies.

a.4 Are currently-high-cost technologies or pre-commercial technologies fostered by this program?

Yes, as mentioned in response to the previous question, this proposal contemplates a separate production credit level (determined by a separate bid process) for technologies designated as "emerging." The extent to which high-cost technologies or pre-commercial technologies that are supported by RD&D funds would also be eligible to receive production credits should be a matter reviewed in coordination by the agencies administering the renewables and RD&D programs.

a.5 How is renewable self-generation handled? Is self-generated renewable energy eligible for Renewable Energy Credits, or for other means of support?

Renewable generation should be eligible for production credits only if it is sold through the grid to either the Power Exchange (or ISO) or to an end-user. Renewable self-generation thus is not eligible for production credits except for that portion that is a net delivery to the grid (that is, the surplus of generation over consumption). One reason for this restriction is that it may be administratively difficult to determine how much renewable energy is delivered for on-site consumption. In the case of net metering – where only one meter is allowed – only the net generation can be determined

Off-grid renewable self-generation applications should not be eligible for production credits. One reason for this restriction is that such applications are typically not metered. In addition, even if such an application were metered, public policy should not advantage electric applications over other applications (for example, compare a windmill that directly pumps water with a windmill that generates electricity which is then used to pump water). Finally, off-grid applications will likely avoid the CTC and the public goods surcharge that supports the production credit program. This avoidance would result in cost shifting to other customers and should not be supported by the program.

a.6 How are hybrid fossil-fuel/renewable facilities handled?

Production credits should be awarded only to the portion of kilowatt-hour production that is renewable as defined in the response to question a.1.

a.7 Does out-of-state generation qualify for Renewable Energy Credits? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

Out-of-state generation will be eligible for production credits provided the energy is sold to in-state end-users (see the response to question a.1). Commerce Clause concerns probably prohibit any restrictions on the applicability of this program to out-of-state generation.

a.8 If hydro is included, how are practical issues associated with hydropower handled?

Hydro is not included. See the response to question a.1, above.

a.9 How is utility-owned generation of distributed renewables handled? Is it eligible to receive RECs or surcharge funds? Does the proposal permit RECs or surcharge funds to accrue to distributed or other renewable applications that may involve the cross-subsidization of generation with T&D savings, or vice-versa? Does the proposal permit or prohibit distributed or other utility-owned renewable power not sold through the power exchange to receive credits or surcharge funds?

Note: the CPUC ruled that during the five-year transition to direct access, UDCs must sell all of their electric generation (presumably central or distributed) through the Exchange, and must serve their customers with power purchased solely through the Exchange. Taking power outside of the Exchange is prohibited. Some applications of distributed renewables may not, however, lend themselves to sale through the Exchange.

As mentioned in the response to question a.1, distributed renewable generation may be an exception to the general prohibition against providing production credits to energy-producing facilities that are under cost-based or PBR-type regulation, because these facilities may serve primarily distribution functions rather than energy generation (see footnote 1). As also mentioned previously, this is an exception that should not be made until the Commission addresses issues – such as cross-subsidization – involved with such facilities.

Even distributed renewable generation that is not utility owned but which is owned by a utility (or UDC) affiliate involves issues of market power, self-dealing, and cross-subsidization. Affiliate ownership could also be inconsistent with functional unbundling and with the Commission's requirement that all UDC power be bought and sold through the Power Exchange. Again, these are issues the Commission must address before such distributed renewable generation facilities should be eligible to receive production credits.

a.10 What is the level for the requirement?

While the surcharge-funded production credit program does not require that a minimum purchase requirement be specified, it does analogously require that the level of the surcharge funds be specified. The surcharge as a portion of customer bills should be uniform statewide.

A surcharge funding level of $100 million per year has been proposed for the three investor-owned utilities. Such a level is achieved by a surcharge of approximately 0.6% of 1995 total electric revenues in the utility service territories. A surcharge of 0.6% of revenues should be applied statewide.

This level of the surcharge is designed to support a level of renewables development comparable to the renewable resources selected in the BRPU process, a total of 440 MW. Assuming an 80% capacity factor, and assuming that the above-market cost of renewables is 3 cents per kilowatt-hour (for example, renewable costs of 5.5¢/kWh compared to market prices of 2.5¢/kWh), then the total above-market cost of 440 MW of renewables is $93 million per year (440,000 kW X .80 X 8760 hours X $.03/kWh).

Initially, if legislation is not enacted by 1/1/98, the 0.6% surcharge should be applied by the Commission to entities under its jurisdiction. The surcharge should be extended by legislation to apply statewide on a nonbypassable basis to all grid-connected end-users. The specific funding level should then be decided as part of legislative action.

Note that this proposal does not require that individual customer surcharges be collected on a per-kilowatt-hour basis. In order to avoid cost shifting, both CTC and Public Goods Charges could be implemented on the basis of a combination of energy and demand, or on a percentage-of-bill basis.

How does this level relate to the level of renewables from 1990 to the present?

There is no guarantee that the proposed level for surcharge funds will preserve or increase the level of renewables compared to current or historical levels. The purpose of this proposed public policy program is to secure environmental benefits, diversity benefits, and other public goods associated with renewables. This program introduces competition among renewable producers to lower the cost to society of securing those benefits. This is an appropriate strategy when benefits have not been precisely quantified.

Does the level of the requirement increase over time?

No.

a.11 Describe how, if at all, the compliance obligation adjusts during a transition period.

The requirement may increase slightly over time in response to changes in kilowatt-hour sales and to inflation, as described in the response to the previous question. The major impacts of the program over time will be due, however, to the manner in which production credits are awarded to projects. The proposal is that surcharge funds should not be allocated in a single year. Rather, the proposal contemplates a five-year phase-in period. One fifth of the surcharge funds would be awarded each year beginning in 1998 until the maximum level is allocated in 2002. Once funds are awarded to a project, and that project begins production, that funding level continues for 10 years. The results of this allocation method, with the simplifying assumption that projects begin production in the same year that funds are awarded and that there is no inflation, are shown in Table 1:

Table 1

Illustration of Costs Over Time of Surcharge-Funded Production Credit

	Production credits initially awarded in ... 1998	1999	2000	2001	2002	Total payments by year
	Production credit payments by year (M$)					(M$)
1998	20					20
1999	20	20				40
2000	20	20	20			60
2001	20	20	20	20		80
2002	20	20	20	20	20	100
2003	20	20	20	20	20	100
2004	20	20	20	20	20	100
2005	20	20	20	20	20	100
2006	20	20	20	20	20	100
2007	20	20	20	20	20	100
2008		20	20	20	20	80
2009			20	20	20	60
2010				20	20	40
2011					20	20
	200	200	200	200	200	1000

Table 1 assumes that the first award of funds occurs in 1998, and that one-fifth ($20 million per year) of the total funding ($100 million per year) is awarded to projects in that year. Assuming for the sake of illustration that projects begin operating immediately, this award leads to production credit payments of $20 million per year which continue for 10 years, through 2007. Thus, the "vintage-1998" projects receive a total of $200 million ($20 million per year for 10 years). The second award of funds occurs in 1999, and results in an additional $20 million per year of production credit payments being distributed through the year 2008. The last award is made in the year 2002. Payments due to that award continue through 2011.

The last column of Table 1 shows the total amount of production credit payments by year that result from the five different funding awards. The amount of production credit payments ramps up as a result of the five incremental awards made in the years 1998 through 2002. The maximum payment level ($100 million) is reached in 2002, and total continues at that level through 2007. After that, the total declines as the end of each 10-year period is reached. Since each of the five "vintages" (1998 through 2002) receives a total of $200 million ($20 million per year over 10 years), the grand total of funds distributed to projects is $1 billion.

The administering agency should have some discretion in the implementation of the program. For example, since it is unlikely that all projects which are awarded an allocation of funds will come into operation, more than one-fifth of the funds could be allocated in the initial years. Allocations in later years could be adjusted to account for the success of projects in initial years while assuring that the overall funding cap was not exceeded. That is, funds initially allocated to projects that do not proceed to construction and operation could be reallocated in subsequent years.

The sponsors also anticipate that the administering agency would impose certain minimum requirements on bidders. As an example, "bid bonds" – where bidders must post a bond equal to a certain percentage of their bid – might be required. Bid bonds are common in competitive awards, and State agencies, including the California Alternative Energy and Advanced Transportation Authority identified in response to question d.1, have experience in their administration.

There appear to be two basic options for the collection of surcharge funds within the constraint that the surcharge not exceed the proposed level ($100 million per year):

1. Surcharge funds could be collected "as-needed," resulting in a surcharge level which varies from year to year; or

2. Surcharge funds could be collected as a fixed amount each year, resulting in a "fund" that would cover a portion of future production credit payments.

Table 2 illustrates these options, using the payment pattern shown in Table 1 as a basis for the illustration:

Table 2

Illustration of Options for Collection of Surcharge Funds

	Proposed total payments by year	Collect as needed -- varying surcharge	Constant surcharge*
1998	$20 M	$20 M	$100M
1999	40	40	100
2000	60	60	100
2001	80	80	100
2002	100	100	100
2003	100	100	100
2004	100	100	100
2005	100	100	100
2006	100	100	100
2007	100	100	100
2008	80	80	
2009	60	60	
2010	40	40	
2011	20	20	
	1000	1000	1000

* Ignores interest on undistributed balances

In each case the total amount of funds collected equals the total amount of funds distributed– $1 billion. Table 2 simply shows different time-patterns for collecting the funds.

The first column of Table 2 shows the proposed schedule of payments, as derived in Table 1. The second column of Table 2 illustrates the first option for collection, in which surcharge funds are only collected as they are needed.

The third column of Table 2 illustrates the constant surcharge option. The total payments – $1 billion – are collected as a constant $100 million per year surcharge over 10 years. This example ignores the effects of interest. Either more production credit payments could be made or a lower surcharge could cover the proposed payments if the surcharge funds were placed in interest-earning accounts until they were distributed.

The proponents of this proposal do not have a strong preference for either option for collection of surcharge funds. There are several considerations that decision-makers should address. A key point, however, is that the stream of production credit payments pledged to renewable projects when they win an award of funding be secure. For the purposes of financing renewable projects, renewable developers must have assurance that the funds will be provided, that is, the funds must be "financable."

Additional considerations include whether the constant surcharge option will increase the "financability" of projects since future production credit payments could be partially backed by funds already collected. Such funds should be securely obligated to the projects to which production credits have been awarded.

The sponsors believe that whatever measures are incorporated by the administrator should be simple and straightforward. The intent of the sponsors is to develop a program that is simple yet effective in allocating funds for continued renewable development. While we believe the administrator should have discretion in actual administration, the administrator should also be provided with guidelines to assure that the original intent of the proposal is maintained.

a.12 Does the proposal include a uniform requirement for all electric providers, including utilities, on a statewide basis?

Yes. The surcharge should apply to all California retail electric providers on a nonbypassable basis. If legislation is not enacted by 1/1/98, then the surcharge should be applied initially to all CPUC-jurisdictional retail electric providers, again on a nonbypassable basis.

a.13 What is the time horizon for the program?

Note: Financing of new renewable facilities, which increases competition, may be contingent on an expectation that a market for renewable power will exist for an extended period of time.

The program is proposed to be reviewed in the year 2000. The program should terminate – in terms of new awards to new projects – after the year 2002, when the maximum level of funding would be achieved. This "sunset" provision will not affect the financing of renewable facilities in years preceding the review, since production credits awarded in those years would be guaranteed for a ten-year period to those specific facilities.

a.14 Is the requirement established on a percentage of megawatts or percentage of megawatt-hours basis?

Production credits are proposed to be provided only a per-megawatt-hour basis.

a.15 Does the proposal establish floors for certain technology types?

No.

b. Where Is The Obligation To Comply?

b.1 On whom is the requirement applied? Is the requirement applied only to entities under the Commission's jurisdiction, or is it applied statewide?

The surcharge-funded production credit program does not impose a minimum purchase requirement on any entity. Rather than requirements and non-compliance penalties, this proposal provides the production credits as positive incentives for the development of renewable energy. The production credits are funded by a surcharge that should be applied on a nonbypassable basis to all grid-connected end-users in California. If legislation is not enacted by 1/1/98 the Commission should implement a nonbypassable surcharge applied to grid-connected end-users subject to the Commission's jurisdiction.

The surcharge should be applied statewide. Initially, if legislation is not enacted by 1/1/98, the surcharge should be applied by the Commission to entities under its jurisdiction. The surcharge should be extended by legislation to apply statewide on a nonbypassable basis to all grid-connected end-users.

b.2 Are regulated retail providers treated similarly to unregulated retail providers?

Yes, as long as unregulated retail providers are subject to the nonbypassable surcharge.

b.3 What is the penalty for non-compliance? Should this penalty be interpreted as a cost cap for the program?

As mentioned in the response to question b.1, the surcharge-funded production credit program does not involve a penalty for non-compliance. The level of surcharge funds defines the cost cap for the program.

b.4 How is non-compliance determined?

NA.

b.5 What provisions add flexibility to compliance, if any?

NA.

b.6 How does the program ensure that the policy and its costs are nonbypassable, such as the CTC or the Public Goods Charge?

The surcharge for renewable energy is identical in form to the CTC and the Public Goods Charge, except that it should be extended by legislation to apply to all grid-connected end-users throughout the state.

c. How Are Renewable Energy Credits Initially Allocated?

c.1 How are Renewable Energy Credits generated from existing renewable facilities (QFs and utility-owned) initially allocated?

NA.

c.2 What is the relationship of the allocation of renewable energy credits and the CTC or Public Goods surcharge?

NA.

c.3 If customers or ratepayers are initially allocated Renewable Energy Credits, how are the credits administered?

NA.

c.4 How would the proposed Renewable Energy Credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make them more or less cost-effective to ratepayers?

NA.

c.5 How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

NA.

c.6 Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

Existing utility-owned renewable resources would be eligible for production credits only if they were divested and they made significant new capital investments (see the response to question a.1). As a result, the value of existing assets should be largely unaffected by this proposal, since in essence only the future increment to the asset is eligible for production credits. Thus, this proposal should have little effect on incentives for divestiture.

d. How Is The Program Administered?

d.1 What agency certifies Renewable Energy Credits?

This proposal does not require that generation from every renewable project be certified. Only those new projects which have won an allocation of production credits must have their kilowatt-hour generation and sales to California end-users verified before production credit funds are distributed. This proposal suggests that the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) may be an appropriate independent agency to administer this program, although legislation could designate another agency if that were deemed appropriate.

There are two different responsibilities that the administering agency has under this proposal. The first responsibility is to allocate funds to projects through a simple auction mechanism for the cents-per-kilowatt-hour level of the production credit. The second responsibility is to distribute the surcharge funds in accordance with the production credit level awarded and the amount of energy generated.

CAEATFA is an independent agency that appears to have the necessary expertise and resources to administer this program. Its Board includes the President of the CPUC and the Chair of the California Energy Commission, as well as representing the State Treasurer, Controller, and the Department of Finance. Its administrative staff is within the Department of the Treasurer. CAEATFA has experience in financing independent projects, including evaluations of due diligence.

In an initial phase of this program, which may be necessary if legislation is not enacted before January 1, 1998, the Commission would have oversight responsibility for the administration of this program. Administration should be delegated to an appointed board or contracted to an independent party.

d.2 What mechanisms are proposed for trading of Renewable Energy Credits?

NA

d.3 What mechanisms are proposed for program oversight and mid-course corrections?

As described in the response to question d.1, this proposal should be implemented by legislation statewide, and administered by a State agency. If legislation is not enacted by 1/1/98, the Commission would have oversight responsibility. The program should be reviewed in the year 2000 before subsequent allocations of production credits are made.

There are a number of administrative details – such as ensuring that projects that have been awarded a credit allocation are actually proceeding to production (and credit use), or if they are not, re-allocating the credits to a new auction – which should be left to the discretion of the administering agency or board.

d.4 What agency monitors and enforces compliance with the program, and how is it carried out?

As mentioned in the response to question d.1, the California Alternative Energy and Advanced Transportation Financing Authority is suggested as an administrator for this program. Its responsibilities will be (1) to administer the auction, including accepting bids from eligible projects and (2) distributing funds, which involves the verification of renewable kilowatt-hour generation and sales to California end-users from winning bidders.

e. Cost-Related Issues

e.1 What are the costs associated with the program, and who pays?

The surcharge should be applied on a nonbypassable basis to all grid-connected end-users statewide. As mentioned in the response to question a.10, the surcharge is proposed to be 0.6% of 1995 total electric revenues, which is approximately $100 million per year for the investor-owned utilities. If legislation is not enacted by 1/1/98, then initially the surcharge should be applied to all grid-connected end-users under the Commission’s jurisdiction. Ultimately, the specific funding limit should be determined by legislative action.

After implementation, program costs and effectiveness can be measured on the basis of the cost-per-kilowatt-hour value of the production credits needed to support new projects.

e.2 What cost-containment measures, if any, are provided?

See the response to question e.1.

e.3 If the program utilizes floors for certain technology types, what are the cost implications?

Floors for technology types are not proposed in this program.

e.4 Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

No.

e.5 How is competition within and between renewable technologies encouraged?

All renewable technologies compete to receive production credits – which represent the increment above market that renewables need to compete with conventional generation. The competition among renewables means that production credits are awarded only to those renewables that are closest to market.

Between existing renewables facilities and potential new facilities?

Such competition is encouraged by this proposal only to the extent that existing facilities leave existing contracts or leave cost-based or PBR-type regulation and make significant new capital investments. See the response to question a.1.

e.6 What implications, if any, does the proposal have in defining the roles of the LDC and of competitive suppliers of electricity?

None. The proposal is compatible with any number of roles for the LDC and competitive suppliers of electricity.

e.7 What is the consistency of this proposal in relation to cost-related guidance provided by the Commission Roadmap?

The Commission Roadmap Decision did not specify a level of funding. This proposal provides a firm cap on overall costs.

f. How Does The Program Fit With Other Aspects Of Electric Industry Reform?

f.1 Is the program compatible with existence of an Independent System Operator? A Power Exchange? A Direct Access Market? Is the proposal consistent with the Commission's vision of the role of the Power Exchange and ISO?

Yes.

f.2 Is the proposal dependent in any way on the Power Exchange and or ISO? If so, are any additional protocols necessary?

No. Since decisions to build new renewable facilities are left to the market (with the incentive of production credits for new renewable energy), the competitiveness and cost-effectiveness of renewables will be enhanced, of course, by a properly functioning Power Exchange and ISO, as well as by the multiple purchasers provided by a Direct Access market.

f.3 Does the proposal involve conflicts of interest between distribution and competitive retail service?

No.

f.4 How does the program avoid conflicts of jurisdiction between state and federal levels?

State-federal jurisdictional issues are not believed to arise under this proposal.

f.5 What is the relationship between the proposal and Direct Access "Green Marketing"?

This proposal encourages the development of "Green Marketing." Those renewable projects that are best able to sell their attributes – including price stability, as well as environmental benefit – to direct access customers will best be able to compete in the market, and require a lower production credit. Thus, those projects that are best at marketing will be favored to win a production credit allocation in the auction.

f.6 What is the relationship between the proposal and performance based ratemaking (PBR)? Does the proposal place Renewable Energy Credits under PBR, or exclude Renewable Energy Credits from PBR?

This proposal is independent of PBR.

f.7. Does the program create any potential market power problems involving the generation market or Renewable Energy Credits?

No.

f.8. How does the proposal relate to any consumer protection or consumer education efforts? For example,

a) Rules for New Entrants. Does the proposal entail any licensing requirements for new entrants?

No. The only requirement is that renewable projects that wish to be awarded production credits must be determined to be eligible.

b) Consumer Education. Does the proposal require any consumer education? For example, how does the proposal protect consumers from "green marketing" programs where marketers collect twice – once for credit sales and once for "green" power sales, thereby not increasing total green power?

This proposal avoids the specific problem mentioned in the example. This proposal encourages green marketing (see the response to question f.5). At the same time, this proposal requires verification of renewable kilowatt-hours before production credits are provided (see the response to question d.1).

There will still be a need for consumer protection activities. The same renewable kilowatt-hours should not be marketed to two different consumers, for example.

f.9 How, if at all, does the proposal relate to RD&D programs funded by the Public Goods Charge?

This program will help mature renewable technologies become competitive with conventional energy supplies. It will also help emerging technologies become market competitive. Less-mature renewable technologies that nevertheless promise important societal benefits will depend in part on RD&D, energy efficiency, or other public goods funding for their continued development. These other sources of funds can be augmented by the surcharge/production credit funds provided by this program.

f.10 How, if at all, does the proposal relate to energy efficiency programs funded by the Public Goods Charge?

Renewable self-generation, which is not covered by this proposal (see the response to question a.5), may be a component of energy efficiency programs.

f.11 How does this proposal affect the CEQA compliance work recently initiated by the CPUC?

This proposal will lead to development of new renewables. It does not assure that existing renewables will remain in production. Thus, the net effect of the proposal should be estimated and included in the overall impacts of the Commission's proposals.

g. Legislative Requirements

g.1 Can the PUC implement this proposal by itself, or is legislation needed? What is the status of entities not under PUC jurisdiction in this program?

To implement this program on a statewide basis, legislation is required. If legislation is not enacted by 1/1/98, then the PUC should implement this proposal for those entities within its jurisdiction.

As mentioned in the response to question b.1, the surcharge should be applied statewide, to include all electric end-users on a nonbypassable basis. If legislation to extend the program statewide is not enacted by 1/1/98 then the program should be initially implemented for CPUC-jurisdictional entities.

g.2 What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the Commission's 1998 implementation goal?

- The surcharge must be put into place.
- An administrator – to run the auction that determines production credit levels, and to verify renewable kilowatt-hours and sales to California end-users from "winning" projects" – must be selected.
- The administrator must design procedures for the auction and for the provision of production credits.

Insert Letter (see hard copy)

4. Positions of the Parties in Favor/Neutral/Oppose

Comments of the CPUC's Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

DRA/UCAN/IPP conditionally support this proposal because it provides for cost certainty. DRA/UCAN/IPP's condition for supporting this proposal is that it include the following:

1. The implementing entity may modify the credit auction between auctions avert gaming.

2. The Commission should advocate statewide adoption of the program and may terminate the program for IOUs if it is not enacted statewide within a reasonable interval.

3. UDCs must pass through local T&D benefits to accelerate the commercialization of distributed renewables owned by customers and competing providers.

4. Credits cannot accrue to distributed renewables owned by UDCs or affiliates. UDC-owned distributed renewables would conflict with key aspects of restructuring.

Comments of AWEA

OPPOSE. Surcharge/subsidy approach is not a minimum purchase requirement for renewables, thus is inconsistent with Commission's decision and is less efficient than market standards approach. Proposal fails to recognize environmental and diversity benefits of renewables as required under current law. Amount of funds proposed would support less than 20% of current level of renewables. Administrative disbursement of funds is subject to inefficiency, gaming, and practical pitfalls. Program would result in new renewables at earliest 2-5 years after policy adoption and potentially later if winning bidders fail during their development stage. Annually, one moderately large project could absorb all available funds.

Comments of CBEA

Concur with AWEA. The proposed surcharge/subsidy approach is not a minimum purchase requirement, and is not consistent with the Commission's decision. The proposed program is not available to existing renewables, is intended to support development of new renewables, and thus would do nothing to support the existing California renewables industry. Even if fully utilized, the proposed amount of funds would support eventual development of less than 20% of the level of energy provided by the existing renewable industry. With the low-bid-wins-the-subsidy approach, development of diversity is very doubtful, with only one type of renewable probably surviving.

Comments of GEA

Concur with AWEA. With the proposed scheme of low bid by a planned renewable project winning the subsidy, a minimum of three to five years will pass before any new renewables are completed. If a planned project wins the subsidy, funds are tied up. If the project fails during development (many do) the funds go back into the pot, and will produce nothing for even more years. The proposal invites gaming, where a renewable subsidized because it has another purpose will bid lowest, reaping a subsidy it didn't need to operate, and denying funds for use in other renewable development.

Comments of STEA

Concur with AWEA. The administrative burden of bidding and awarding funds, followed by monitoring development progress of winning projects, will be large. What milestones must be met?; How much time is given before funds are retrieved?; etc. With the small amount of money involved in this proposal, one moderate-size renewable project could tie up all the money each year. Under this proposal, you'd know exactly what you're paying, but would have no idea what you get for the money, as contrasted to the AWEA proposal, where you know what you get and depend on free-market competition to keep costs low.

Comments of Some Surcharge-Funded Production Credit Proposers

(Note: Where Surcharge/Production Credit Proposal supporters' names appear independently in these "Position of Parties" subsections, their position is not included in the following position statement made on behalf of the remaining supporters.)

Favor:

1. ***Minimizes/clearly identifies overall costs.***

2. ***Uniform, statewide funding of program.***

3. ***Meets public policy goals in the short and long run:* State agency can focus on projects that produce the public policy goals of improving the environment, conserving**

resources, meeting societal needs, etc. New, efficient, environmentally sensitive technology projects receive support, and customer costs are controlled.

4. Uses effective means for long-term success: This collaborative effort, by a diverse group of stakeholders representing environmentalists, independent producers, municipal sanitation districts, and utilities interests will succeed.

5. ***Has capability for implementation by 1/1/98.***

Comments of Orange County, Sonoma County, the City of Sacramento, NEO Corporation

We support this proposal because it is only for new projects and market driven with funds award through a price only auction. Awards are financeable with a 10-year life. It allows participation by emerging technologies or higher priced green power. This is because they can get funds from the WEPEX, this Surcharge Production Credit and additionally, seek tax credits, grants, etc. Renewables that have a distinct regional benefit may get funds from the benefiting enterprise, such as public or private solid waste operations. Technologies can (should) compete by marketing to ratepayers their specific green power.

Comments of the Union of Concerned Scientists

Oppose.
Pros: Exclusion of hydro avoids subsidization of a mature, fully commercialized technology and problems with annual variability.
Cons: Conceived as an alternative to RPS, but inadequate. Does not maintain existing renewables. Does not guarantee any set level of renewables development. New project awards end after five years. Price-only bid may encourage under-bidding.
Other: Although a renewables surcharge alone is inadequate, as a supplement to an RPS a small, focused charge could help promote a greater diversity of renewables options by leveraging some less mature technologies into the RPS.

Comments of Los Angeles Department of Water and Power (LADWP)

The procurement of renewable resources should be the responsibility of some state entity or the state power pool and the above-market costs of compliance should be borne uniformly by all customers served by the UDC on a non-bypassable basis. Rather than having many entities responsible for procurement of renewables, having one entity responsible for the state's procurement of renewable resources will minimize the transaction costs of compliance. The level and diversity of renewable resource mix should be established by the state legislature. The renewables program should be reviewed every five years or so.

Comments of Southern California Edison

This proposal has many positive points and should be considered by the Commission as an alternative to the MRPR. This proposal explicitly sets the cost of the program by setting the level of the surcharge. Moreover, this cost is known and visible to customers, regulators, and legislators. The proposal does not provide any additional subsidies to existing facilities but does provide incentives to build a new generation of renewable energy projects. This proposal limits the administrative impact to a small group of market participants and can be readily extended statewide through legislation.

Comments of CalSEIA/SEIA/ETDD

SUPPORT WITH MODIFICATIONS
Diveristy and Emerging Technologies: Since lowest bid price is only determinant for winning credits, well-established technologies are expected to recieve all credits. Depending on level of funding, diversity, even among low, current-cost, well-established technologies, may be limited. To provide any support for newer, emerging technologies, some portion of the surcharge must be set asside (see CALSEIA proposal). With moditication, surcharge approach provides similar competitive funding process to RD&D process, which is appropriate for technologies transitioning from RD&D to full commercialization.
Credit Contract Term: Ten year term is advantageous, especially for emerging technologies, as it permits ten year project financing. Even longer contract term would allow longer financing amortization resulting in still lower annual costs and lower overall annual program cost.

Comments of the California Integrated Waste Management Board

Oppose: The production credit model by providing ten years of guaranteed prices will result in the construction of a limited amount of new renewable generation.

The proposal ignores the problem that renewables generation technologies cannot presently economically compete with natural gas and hydro-electric power, and that renewables offer a variety of social and environmental benefits.

Would expect that the current level and diversity of renewable generation will decline under this proposal. The bidding process may become subject to "gaming" by bidders, and will tend to reward lower cost technologies and financially stronger bidders.

Comments of Don Augenstein

One advantage of the EDF et. al. proposal is that more renewables may be obtained for given funds, as bidding mechanisms presumably develop least-cost projects first. Drawbacks are the low surcharge and end of funding after 10 years. At anticipated $0.02-0.03 value for a REC (as some expect) this proposal appears likely to fund a fraction of the renewables--well under half--of several other extant proposals. Low surcharge, thus low renewables funding seem a serious disadvantage as it stands.

Comments of SoCAL Gas

SUPPORT - Major attribute is the clear identification of the cost of the program.
Lets the consumer know the cost of energy diversity up font.
Closely aligned with the CPUC's desire to reduce the cost of electricity in Califomia.
A kWh production credit applied only to energy actually sold.
Nonbypassable surcharge is not included as part of investor owned utility rates.
The program is relatively simple.
All renewable technologies compete for limited subsidies.
Based on a price-only, first-price auction for a fixed production level for 10 years.
Requires no penalties.
No need for a tradeable energy credits market.
Has a sunset provision.

Comments of SDG&E:

Support:

- Promotes new renewables in lieu of funding existing projects that have already received subsidies.
- Cost cap via surcharge limit of $100-125 million for all California.
- Provides stream of payments up to 10 years for new projects; leverages financing.
- Program cost uniformly allocated to consumers statewide.
- Meets goal of providing minimum level of renewables generation.
- Relatively simple to administer by an existing state agency which has the requisite expertise.
- Unbundled surcharge.
- Emerging technologies floor could be accommodated.
- Supported by broad cross section of industry and environmental parties.

Comments of IEP

- Does not address existing renewables.
- In the absence of full direct access, does not provide adequate price signals to sustain competition for the production credits. For example, in the absence of any direct access, the sole purchaser is the utility under a SOl contact, and the price paid to all renewable producers will be the marginal clearing price of the PX. The only variable affecting allocation bids will be the producer's operating costs, which remain relatively fixed over time. The absence of buyer/seller price variability will likely result in a single entity garnering all the production credits

Comments of PG&E

PG&E prefers the surcharge proposal over the various minimum renewable purchase requirement proposals, because we believe the latter approach will be too complex to implement in an increasingly competitive generation market. We also prefer this methodology because it uses market mechanisms and the entrepreneurial energy of future renewable providers to encourage the development of new renewable resources. We believe that many of the existing renewables (both those we currently own and those whose power we contract for) can survive the transition to a more competitive market without special actions.

4.3. Adjunct Proposals

A. Electricity From Landfill Gas and Other Biogas; Climate Active Gas Mitigation in Utility Restructuring

Submitted by: Sacramento County, Yolo County, Monterey County, International Power Technology, Royal Farms, Institute for Environmental Management, EMCON

Preface

This proposal specifically addresses renewable electricity from biogas as an avenue to reducing climate active (or "greenhouse") gas emission in the restructured electric utility industry.

The proposal is intended to serve as an adjunct to any of the other candidate proposals from the ad hoc renewables working group which address the wider range of restructuring issues connected to the proposed Renewable Energy Credit.

1. Interpretation of Commission Goals; Relationship of this Proposal to Commission Goals in Restructuring

The CPUC, in its Restructuring Decision of December 20, 1995, commits to fostering electricity from renewable resources. The commission's decision clearly allows for development of strong roles for diverse renewables, including wind, solid biomass, geothermal energy, photovoltaics, solar thermal, and others. A major justification for renewables' use is their environmental benefits, including, importantly, their mitigation of the climate effects of fossil fuels.

Among the renewable energy resources already significant in California is electricity fueled by "biogas" derived from the decomposition of various organic wastes. This document first discusses the current and potential future role of renewable electricity from biogas within the restructuring industry. The purpose is to provide an overview of the status, and particularly the existing environmental issues, with electricity from biogas. It then proposes an approach to maximize climate change benefits from electricity from biogas within a restructured industry. Restructuring implications of the approach are presented.

2. Program Background, Overview and Description

a. Electricity from Biogas in California

Methane rich gas, ("biogas"), is produced by microbial decomposition of organic wastes including municipal solid wastes, manures, and sewage sludges. In this document, biogas is considered to include all methane-rich gas generated by microbial action from existing wastes, whether in landfills, or anaerobic digestion of manures, sewage sludges, and other wastes such as from food processing. Such biogas can and does already fuel electricity generation in a variety of commercial equipment, with present prime movers including internal combustion (IC) engines, combustion gas turbines and steam turbines.

Approximately 200MWe of net capacity are fueled by biogas in California. The largest category (about 75%) of biogas-based generation is at municipal waste landfills, from "landfill gas" (LFG). From statistics developed in cooperative solid waste industry/USEPA-sponsored work, present and contracted generation capacity of the landfill gas industry in California is as shown in Table 1. Electricity from the anaerobic digestion of sewage sludge and food waste may be about 25-30 MWe and from manure biogas presently about 1MWe. The electricity from biogas is nearly all baseload (85% or greater annual capacity factor) as biogas, which is non-storable, is typically collected 24 hours/day.

b. Electricity from Biogas, Atmospheric Methane Emission, and Climate Change

Renewably based electricity is designated a "public purpose" program by the CPUC. One major public purpose justification for renewables is environmental benefits accruing from their use. One environmental benefit of renewables, now seen as extremely important, is addressing climate change by reduction or mitigation of the emission of climate active gases. Mitigation of climate change and climate active (i. e. "greenhouse") gas emissions has become a major state, federal and international concern, as well as the subject of a major international agreement17 It is an electric utility concern, such that nearly all California utilities are signatories to the voluntary U. S. Climate Challenge program, whose major purpose is to reduce climate active gases.

In brief, recovery and use of biogas for electricity generally provides corresponding reductions in emissions of methane to the atmosphere, as discussed in more detail in subsequent sections and notes. Conversely, without biogas energy uses, major sources of biogenic methane emission escape control either partially (landfills) or entirely (manures)18. As a "greenhouse" gas, methane's potency on a weight basis is over twentyfold that of carbon

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17The United States is signatory to the Rio Treaty, (Framework Convention) wherein it has agreed to actions to ensure that greenhouse gas emissions in the year 2000 do not exceed 1990 level. It is very likely that the U.S. will be in violation of this treaty condition by 2000.
18 Even with numerous extant air emission regulations, no statutes or regulations (local, state, or federal) address atmospheric methane emissions per se; methane abatement instead subordinates to control of other biogas components (VOC's). Unless air pollutant emissions dictate control under statutes, major emitters of methane may escape control entirely.

dioxide. Thus capture and use of biogas from these sources helps substantially in addressing global warming. Reduction in methane emissions also addresses other adverse

TABLE 1. LANDFILL GAS ELECTRIC GENERATION IN CALIFORNIA

(Net megawatt capacity at site; typical sites average 85% [or more] of net capacity annually) (Source: Thorneloe and Pacey, 1996)

SITE		NET CAPACITY, MWe
Altamont, Contra Costa County		5.0
American Canyon, Solano County		1.55
Austin Road,		0.75
BKK-1, Torrance,		3.4
BKK-2, Torrance		6.4,
Central of Sonoma County,		6.0
Central of Yolo County		1.8
Corona		2.0
Coyote Canyon, Los Angeles County		12.0
Crazy Horse, San Luis Obispo County		1.28
Guadalupe, Santa Clara County		2.5
Marina, Monterey County		1.9
Marsh Road, Santa Clara County		2.0
Mountain View, Santa Clara County		3.0
Newby Island, Santa Clara County		4.0
Olinda, Orange County		5.0
Oxnard Ventura County		5.25
Otay, San Diego County		3.4
Palo Alto, Santa Clara County		1.2
Palos Verdes, Los Angeles County		7.0
Penrose, City of Los Angeles		8.5
Puente Hills, Los Angeles County		47
San Marcos, San Diego County		1.32
Santa Clara, Santa Clara County		1.42
Santa Cruz, Santa Cruz County		0.66
Spadra, Los Angeles County		9.0,
Sycamore Canyon, San Diego County		1.32
Temescal Road,		1.31,
Toyon Canyon, City of Los Angeles		8.5,
West Contra Costa, Contra Costa County		2.6.
	Total	157

phenomena, particularly stratospheric ozone depletion. Most relevant for the electric utility sector, methane emission mitigation resulting from biogas-to-electricity provides uniquely large per-kilowatt "offset" to otherwise adverse greenhouse effects of fossil CO_2 emission from electric power generation. Fueling an estimated potential of 600MWe or more of California electricity with biogas will offset about 10% of the fossil CO_2 emissions associated with electricity generation in California (further discussion in Note A-1)

c. Recognition of Biogas Benefits

The climate change benefits of electricity from biogas are well-recognized by the electric utility industry and utility trade organizations. (Note A-2). These climate change benefits are also recognized and promoted in an array of government programs and initiatives (Note A-3).

As but one example, four (of 50) action items in the 1993 Presidential Climate Change Action Plan deal with energy uses of biogas.

The Intergovernmental Panel on Climate Change (IPCC) working value for methane's greenhouse potency is about ninefold that of CO_2 on a molecule-for molecule basis, or a factor of 24.5 higher than carbon dioxide on a weight basis; (these values are also used by the U.S. EPA and United States Department of Energy [DOE]) Based on this, generation of one kWh from biogas as opposed to its emission to the atmosphere effectively offsets carbon dioxide emissions from about 10kWh of fossil fueled power19.

This CO_2 mitigation or "offset" associated with electricity from biogas is well-accepted. It is quantified and reported by most U.S. utilities purchasing and reselling electricity from biogas, as well as their trade organizations. The most active electric utility trade organizations on this issue are the Edison Electric Institute, (EEI), representing Investor Owned Utilities (IOU's), and the Electric Power Research Institute (EPRI). Greenhouse gas mitigation programs of utilities and others are reported under the U. S. Department of Energy's Title 1605 (b) voluntary reporting program for greenhouse gas mitigation efforts. Under the program, methane use reported with electricity from biogas is all taken as equivalent to abating 24.5 times its weight in CO_2 (the standard IPCC/EPA/DOE methane greenhouse value).

d. Monetary Valuation and Cost Effectiveness of Biogas Climate Benefits

"Standard" values are not established for greenhouse gas reductions, but there are several present yardsticks. Valuations (i. e. debits) have been assigned to greenhouse gas emissions in electric resource planning by several states' public utility commissions in the U. S. These have normally been expressed in dollars per ton of fossil CO_2 or dollars per ton of fossil CO_2 emitted or abated, or, when another greenhouse gas is abated, its CO_2 equivalent20. (Values are being assigned in Europe, also. These are typically higher than U.S.) In addition, numerous U. S. utilities have undertaken voluntary projects for the specific purpose of greenhouse gas abatement at various net costs; one example is the "utilitree" tree planting program involving Edison Electric Institute members21. A number of studies estimate costs of slowing climate change. A comprehensive summary of several studies is published by Nordhaus (1991). Based on studies such as summarized by Nordhaus, costs of up to 25

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19 Ninefold offset from methane abatement plus backing out CO_2 from one kWh of fossil power generation. As noted briefly in A-1, it is nearly all fossil fueled power that is displaced by renewables.

20For example, the State of Wisconsin Public Utilities Commission assigns a debit of $15/ton CO2 ($55/ton CO2 carbon) and $150/ton methane emission prevented in electric resource planning. New York Public Service Commission considers a guideline of $20/ton CO2 carbon (5.50/ton CO2) In California, carbon abatement values of $30/ton are considered (Electricity report docket 93-er-94, June 7, 1994).

21 Personal communications, John Kinsman, EEI.

dollars per ton of CO_2 carbon (\$6.80/ton CO_2) might be considered in the "low" range of costs for CO_2 abatement.

Further discussion of greenhouse gas offsets is presented in Note A-4. Example calculations for offsets associated with biogas based generation in Table 2 of Note A-4 show values from 1.4 to 7.5 cents/kWh at equivalent CO_2 abatement costs of \$2.75 to \$5.50/U.S. ton. As discussed in notes A-4 and also A-5, biogas use for electricity does generally result in abatement of atmospheric emissions, and so, represents net "public good" in terms of not only the greenhouse gas but also VOC offsets (Notes A-4 and also A-5).

e. Current Economics and Status of Biogas

Though climate change benefits from biogas to electricity are widely and officially recognized, markets for electricity to grids have been sufficiently adverse, or uncertain, that most biogas from landfills and other wastes still does not find use. Survey work (Thorneloe and Pacey, 1994) has indicated that, as of 1994, only about 300 MWe of landfill-gas-based generation were realized in the U.S. out of a U. S. potential estimated by both the U.S. EPA (EPA 1993) and the Electric Power Research Institute (EPRI, Gauntlett, 1992) to be 5000-7000MWe22. Part of the problem, noted above, is that landfill regulations address only local air pollutants. There is also no direct regulatory authority, or monetary incentive to prevent biogas' greenhouse methane emissions per se to the atmosphere. Another major barrier is economics. Electric power development from many landfills and manure streams--that now emit a great deal of methane to the atmosphere--is more expensive than electric revenues of themselves would justify. This is because of small scale and many other site-specific factors. Combinations of uncertainties and costs have been such that, even with past favorable SO4 electricity purchase prices (applicable in some cases), and past tax credits23, electricity from landfill gas in California developed only about 150 MWe out of gross potential of perhaps 500-700 MWe (for estimate basis see Note A-6). For biogas from manure, percentage of methane recovered to generate electric power is much less than 1% nationwide (Roos, 1995).

Another issue arises as the California electricity industry restructures. In states where utilities remain integrated, and subject to states' Public Utility Commissions' controls, it has proven possible for such integrated utilities to promote greenhouse gas and biogas abatement in projects through Commission directives and guidelines. With present restructuring in California, it is not clear what entity might have responsibility for additional greenhouse gas abatement efforts, beyond those consequent to application of the REC's as now envisioned. To address this situation, a possible approach, developed below, is to adapt REC's to accomplish additional desirable climate active gas abatement.

22Potential in EPA and EPRI refs based on size criteria (>1MWe) and presuming favorable power markets.
23Federal section 29 tax credits effectively provided about 1 cent/kWh to electricity from most LFG projects under binding contract by the end of 1995. Credits will no longer be available for new projects.

f. Statutory Authority to Value Emission Abatement

As noted in several other Renewables Working Group proposals addressed to the CPUC, there exists statutory authority to value environmental benefits of specific generating technologies. The California Public Utilities Code states**:**

> -In calculating the cost effectiveness of energy resources, the Commission is directed to include a value for any costs and benefits to the environment, including air quality [sect 701.1 (c)]

g. Greenhouse Environmental Credit (GEC)

Significant monetary values are estimated for environmental benefits for electricity from biogas (Note A-4 examples). Statute allows these values to be recognized in electric power generation. Thus we propose that environmental benefits, including greenhouse gas and VOC abatement, be reflected by a credit, applied where biogas capture mitigates emissions to the atmosphere24. This credit is provisionally termed a Greenhouse Environmental Credit, ("GEC") assigned each kilowatt generated from biogas25. This would value environmental benefits in accordance with statute, with emphasis to the severalfold greenhouse gas abatement compared with other renewables.

Of course, any valuation such as via the proposed GEC raises questions. The principal question is, what total per-kWh value of a renewable, as related to other benefits, should be assigned to global climate benefits? Monetary valuations of "externalities" are inherently imprecise, having subjective or "value judgment" components26. However almost all arguments in favor of renewables emphasize the same basic components--global change, regional/local air pollution, sustainability, and domestic/local production. If equal weighting were to be assigned to each factor, a ninefold higher climate change benefit should translate to a threefold higher REC value for electricity from biogas compared to other renewables. Even recognizing that some control will take place for certain wastes, additional monetary incentives for any additional biogas used for energy would achieve much additional control. Substantial value for the GEC is thus justified by the additional offset. Here we propose the GEC for electricity from biogas be set equal the REC for other renewables. This would

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24 Applying for example, to manures, landfills and certain sewage and food processing wastes. Excluded from credit, however, would be de novo fermentations of non-waste harvested feedstocks "for biogas"(as for example grasses grown especially for conversion to biogas). These provide no added greenhouse gas mitigation beyond that available from other renewables, thus merit no additional credit.

25 This proposal assumes use of a credit-based approach as favored by the CPUC. A surcharge approach could also be workable and we do not wish to imply that it should be precluded.

26 However values can certainly be established by various criteria--see CEC staff papers in connection with docket 93-ER-94 on valuation of air quality benefits

reflect a premium of 100%, as biogas would receive a total of 2 REC's per kWh generated from it.

Certainly, value of greenhouse gas abatement may be significant, up to several cents/kWh for electricity from biogas (Note A-4). The potential value of the biogas electricity premium based on CO_2 abatement is also addressed in EPA, 1993 which arrives at the same order of value. Both greenhouse gas abatement cost, and cost-effectiveness calculation bases are discussed in note A-7. The calculation basis proposed here is (1) Equivalent CO_2 abatement calculated by methods of the federal Title 1605 [b] reporting program (2) "Reference" electrical generation efficiency stipulated, (3) incremental cost assigned to abatement is that of the added GEC (or REC), that is assignable to climate benefit. On this basis, the cost of carbon abatement at a REC = $.02 is $14/ton CO_2 carbon, i.e., $3.90/ton CO_2, and at a REC value of 0.03 the cost is $ 21/ton CO_2 carbon, i.e., $5.80/ton CO_2.

We also suggest a cost-effectiveness standard for greenhouse gas abatement using the GEC. A limit could be set such that abatement cost does not exceed $25/US ton carbon or $ 6.80 /US ton CO_2 equivalent, calculated as above, adjusted as necessary for inflation. The GEC could apply whenever cost for greenhouse gas abatement falls below this limit. If carbon abatement costs are above this limit, the REC alone could apply or other adjustments made in application of the GEC27. However it is unlikely that this cost limit would be exceeded at anticipated values for the REC.

h. Issues with the GEC

This assignment of increased REC (i. e., via the GEC) to reflect the climate and pollutant benefit associated with biogas use raises several other issues and questions. These include (1) administration, (2) that biogas kilowatts would presumably receive more payment per kWh than is received by other renewables, (3) that biogas kilowatts could adversely affect (or "squeeze out") desirable use of other renewables, (4) rather than assigning electricity from biogas what is in effect a higher REC value per kilowatt, why not "band" biogas, giving it a setaside, or minimum use requirement in the portfolio as proposed for certain other renewables? and (5) is this approach fair to ratepayers? We discuss each of these**:**

For (1)**:** Administration could certainly become complex if GEC's were to be handled independently from REC's. As implied above, we suggest the administrative complexities with the GEC for biogas be minimized by tying it to the REC and handling it exactly as REC for convenience. This should minimize incremental administrative work.

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27 For example, cap or reduce GEC value (in terms of its REC equivalent) such that cost standard is met over specified intervals. This cap could also apply to situations where less incentive is needed to recover biogas, or to address other problems, as from variable REC monetary value. See also response to question C-5.

In the future, however, the GEC might be treated separately and traded independently from the REC. An important feature of greenhouse gas abatement is that it has the same value to the world's environment regardless of where in the world the greenhouse gas abatement occurs. Thus such credits might easily have value and be traded nationally, or even internationally.

(2) The resultant higher sales price likely for electricity from biogas via a Greenhouse Environmental Credit is, in any event, paralleled by the treatment already requested for solid fuel biomass, as well as for presently-higher-cost technologies making the transition into commercial application:

Solid fuel biomass is requested in both AWEA and IEP proposals to be "banded", i.e. to receive a setaside such that most existing solid fuel biomass plant remains or is brought online. (This is also embodied in the legislative approach of AB1202.) It is expected by IEP and AWEA that this will result in higher costs for solid-biomass-fueled power. For solid fuel biomass the justifications listed by AWEA for higher cost and keeping solid-fuel-biomass plants online include (a) waste diversion from landfills (b) prevention of open agricultural burning and (c) forest management benefits. (a bringing indirectly, and b bringing directly, environmental benefits that should be valued consistent with utilities code [sect 701.1 (c)] above) In the case of electricity from landfill and other biogas, the environmental benefits valued consistent with utilities code sect 701.1 (c) are instead simply the increased mitigation of climate active gases--and VOC's in addition (again refer to Note A-4).

In the CEC Energy Technology Development Division (CEC/ETD) staff proposal, higher purchase prices are also advocated for technologies transitioning into early commercial application**;** the higher sale prices would obviously help these toward commercialization. This is another case of higher prices for certain renewable categories, for purposes considered beneficial.

(3) We propose that biogas to electricity should be able to increase without adversely affecting or diminishing use of other renewables. The climate active gas mitigation with electricity from biogas is public good of high importance (internationally, inasmuch as climate change is an international issue). It is directly relevant to, and offsets, adverse global climate impacts of the electric utility sector. There appears no reason that increased biogas use, as justified by added climate benefits, should result in diminished use of other renewables with their corresponding benefits. Providing greenhouse gas abatement meets stated cost-effectiveness criteria, it is proposed here that total allocated REC's should be increased by whatever amount is necessary to accommodate all electricity from biogas (the biogas REC total including the GEC equivalent). In any case, REC's for, and total production of, other renewably based electricity should remain the same as they would be

absent electricity from biogas. This treatment can assure that other renewably based generation is not affected.

(4) For solid-fuel biomass, generation "banding" proposed by other organizations is slightly less than needed to bring online the totality of operating, shutdown and recent BRPU auction-winning solid-fueled plant capacity. That capacity is well-defined. Capacity is also constrained in ways (fuel supply, costs) such that costs might escalate relatively rapidly with any added capacity and power production increments above the "band". In the case of biogas, fractional use for electricity is very low. Potential for additional electricity from biogas may be severalfold the existing level (refer to Note A-6).

A continuous spectrum of costs is expected for electricity from landfills and other biogas sources, depending on scale and other factors. Incremental additional generation (and greenhouse gas abatement) can be expected to respond elastically to price. "Banding" appears too rigid an approach to address this situation. Uncertainty attends estimates, but the degree to which price might affect generation of electricity and consequent methane (greenhouse gas) abatement with landfill gas is suggested by the figures provided in analyses of EPA (1993). When buyback rates rise from $0.04 to $0.06/kWh, (at a favorable [optimistic] project discount rate assumed in EPA, 1993, at 8%), the resulting electric generation and methane abatement, and equivalent CO_2 abatement more than quintuple for the U.S. In EPA, 1993, presuming a buyback rate of $0.06/kWh, U.S. landfill methane abatement rises in the year 2000 to 8.2 million metric tons, equivalent (at official IPCC values) to over 200 million U.S. tons CO_2 abated. It is worth noting that greenhouse gas abatement equivalent to 200 million U.S. tons/year of CO_2 constitutes offset to roughly 10 percent of fossil CO_2 emissions of the U.S. electric utility sector annually--and this is for landfill biogas alone. It is also worth noting that electricity from manure biogas has a wider and somewhat higher spectrum of costs (EPA, 1993, Sharp, 1996); manure methane is estimated to have total climate change impact about 30-50% that of landfill gas (see data of EPA, 1993, Whittier, 1994). It would be expected to have similarly significant price response in terms of power generation and greenhouse gas abatement.

In any event, whatever incremental electricity from biogas does come online in response to price will result in further GHG and VOC offsets, thus public benefit. The allocation of two RECs per biogas kilowatt--via GEC's--lets this resource and its corresponding benefit or corresponding "public good" expand elastically to the extent that it can in response to price. The biogas electricity price premium can be justified on cost/benefit criteria developed on the basis of costs for abating emissions (Note A-4).

At the same time the cost obligation with the GEC approach is not open-ended: First, tying the GEC to the REC determines GEC value in turn by the same competitive factors determining REC value in an active market. Secondly, the eligible biogas-from-waste resource constrains maximum generation to less than 3% of California electricity (likely, about 2%). Finally, as noted, a cost-effectiveness standard can be applied in terms of an upper limit to greenhouse gas abatement cost. It must be emphasized that the overall intent is to apply the GEC to mitigate climate impacts, limiting GEC scope and application to situations where it provides the most cost-effective abatement of climate active (and pollutant) biogas emissions.

(5) A general, certainly major issue with monetization of renewables' environmental, and other benefits--that of fairness**:** Is it fair to charge premium costs for landfill and other biogas and other renewably based power which are passed through to ratepayers?

The utility sector, and ultimately ratepayers, bear responsibility for greenhouse gas emissions. Thus electricity user support of renewable and biogas-based power as discussed here appears as fair as any mechanism to offset environmental and other impacts of electric power production. As noted earlier, one advantage of electricity from biogas for ratepayers is that it is among the most "greenhouse-cost-effective" of CO_2 emission offsets, per kWh. Even at twice the REC subsidy, the ratepayer still gets much cheaper greenhouse gas abatement than with other technologies.

A comment here is that this proposal supports the CEC-ETD staff approach to provide a higher revenue tier for technologies in earlier stages of commercialization. Electricity from manure biogas has significant potential but remains in early development with probably less than 2MWe nationwide, and likely 1MWe or less in California. Manure biogas in particular is a present major source of greenhouse methane in the U.S. A band in which electricity from manure biogas receives higher revenue--possibly by additional RECs beyond the extra from the GEC is appropriate.

i. GEC operation

An RPS standard could require that (for example) 10% of total California electricity generation could be met by renewables, aside from biogas. If biogas eligible for the GEC were to provide an additional 1% of total California electricity generation then the RPS would expand to accommodate biogas-based generation. The RPS would require purchase of power or RECs equal to 12% of generation, i.e., the 10% of other renewables + 2% representing the biogas REC + GEC. (In meeting the portfolio standard biogas based power usually would via the GEC + REC, either count twice, or give rise to two REC's.) This renewables (or equivalent renewable credit) obligation would accrue <u>pro</u> <u>rata</u> to all UDCs (or whatever entities must meet the renewable portfolio obligation according to portfolio standards).

Allocation of 2 REC's per biogas kilowatt via the GEC as opposed to one per other renewable kilowatt, could operate as in the following simplified examples.

1. If (as another example) the RPS were for 15% renewable energy or credits in the mix, the REC credit need would actually be met by purchase of 10% other qualifying renewables plus 2.5% of the electricity from biogas (thus, 5% of power credited from biogas).

2. If a customer in a bilateral agreement were to purchase 100% of electricity supply needs from biogas, and a GEC = 1.0 REC, then renewable energy credits would amount to 200% of those kilowatts. In an active market characterized by many buyers and sellers, it would be expected that extra REC's would accrue value which could return to the customer (in a manner similar to other commercial rebates), and that market mechanisms would exist or develop to realize the REC's value for the power customer to the extent desired.

As discussed the intent with the GEC to obtain added, highly cost-effective greenhouse gas mitigation, but without affecting other renewables' uses. To this end the purchase requirement would be adjusted, annually, by adding to it all REC's (including from GEC's) resulting from electricity from biogas. This would be done as soon as the biogas-fueled generation data were available from the previous years' operation.

j. Concluding Note

In other aspects this biogas and climate active gas proposal would generally conform or be subordinate to, terms of other proposals**:** the proposals include--but are not limited to--that put forth by the California Energy Commission staff (tier approach to foster renewables in early stages of development) and the joint proposal of the American Wind Energy Association/California Biomass Energy Alliance/Geothermal Energy Association and the proposal of the Independent Energy Producers Association. This proposal is intended to be a suitable adjunct to as wide a range of proposals as possible. In cases where other proposals differ, this group is neutral where it feels differing approaches have merit. This group may later state preferences where these exist.

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l. Appendix A--Notes to Overview

Note A-1. Greenhouse Gas/Ozone Loss/Air Pollution Issues:

The generation of power using biogas helps overcome the following problems:

Global warming: Atmospheric emissions of U. S. landfill and other biogas are major factors in global warming, simply because of the enormous quantity of waste and manure, and the climate change potency of methane. In scientific terms, U. S. landfill methane, alone, adds a roughly 1% increment to the total annual increase in radiative forcing due to buildup of all greenhouse gases in the atmosphere (see Augenstein, 1992). To simplify terms, this means it can be considered responsible for about 1% of the "greenhouse effect".

U. S. animal manure impacts from methane emission, are about 30-50% of those from landfill gas (see information in EPA, 1993, Whittier et al 1994).

Stratospheric ozone depletion Methane--including that from biogas--adds significantly to the recent atmospheric methane buildup. That atmospheric methane buildup has given rise to stratospheric changes which have resulted in turn in the recent sharp losses in polar stratospheric ozone, i. e., the "ozone hole". Stratospheric ozone depletion and the "ozone hole" are now international concerns. (Blake, 1994).

Local air pollution. Landfill and other biogas contains organic pollutants. For landfill gas, these pollutants are the focus of federal, state (California) and local air district rules.

While analyses can easily become extremely detailed, it is possible to simply summarize:

As noted in the text, generation of one kWh from biogas can effectively offset the CO_2 emissions from the order of 10kWh of fossil fueled power. (Capture of one molecule of methane as opposed to emission, offsets 9 CO. Since "swing fuels providing extra incremental power over baseload are nearly entirely fossil, an additional fossil CO_2 or more is displaced by any renewable) Consequently, generation of 1-2% of total electric power with landfill and other biogas, which is the potential in a typical utility service area or state such as California, has "greenhouse effectiveness" equivalent to reducing fossil carbon dioxide emissions by that generation 10% or even more.

The abatement of other gas components (VOC's) has substantial further value as does addressing stratospheric ozone depletion.

Electricity production from biogas can help address all of the stated problems. This is very-well-recognized by electric utilities themselves, utility trade organizations, and government agencies (at all levels). As detailed later below, factors 1 and 2 (climate change) drive U.S. electric utility conformance with the climate challenge; EPA and Department of Energy programs promote biogas energy uses for these benefits.

Note A-2. Electric Utilities' Positions

The Edison Electric Institute (EEI), the Electric Power Research Institute (EPRI), and numerous individual utilities are taking positions to support or facilitate member utilities' use of landfill gas power (nearly all purchased from IPP's).

EEI (investor owned utilities)--≈ 70% of the investor-owned utilities (in terms of EEI member electric generating capacity) are signatories to the climate challenge. EEI is strongly encouraging all member utilities which use landfill gas electricity take credit for greenhouse gas offsets to the maximum extent possible, reporting methane abatement fully under the DOE 1605 (b) voluntary program to report greenhouse gas abatement.

EPRI supports landfill gas electricity through studies, (see EPRI 1992 reference, this document) and dissemination of information to member utilities. EPRI also supports renewables and greenhouse gas abatement research.

Individual Utilities have long taken interest in electricity from biogas.

Note A-3. Government Agencies' Positions

International, Federal, State and Local agencies endorse objectives met by landfill gas electricity.

International initiatives include the Rio conference, and a number of related international efforts toward renewable energy and greenhouse gas abatement. Other efforts are exemplified by the International Energy Agency (landfill gas expert working group supporting energy uses) and the Intergovernmental Panel on Climate Change (a major working group tracks methane from wastes).

Federal initiatives include the Climate Change Action Plan (CCAP) and Clean Air Act (CAA), On LFG:

-Under CCAP, USEPA is facilitating landfill gas use via the Landfill Methane Outreach Program (Climate Change Action Plan item # 34) as well as the (related) AgStar program for use of methane from manures (Climate Change Action Plan item # 38).

-Under CCAP, also, the DOE is managing RD&D on methane recovery from landfills (Climate Change Action Item # 37)

-The DOE is also conducting the 1605 (b) voluntary program by which participants report greenhouse gas emission abatement. Nearly all utilities report greenhouse gas offsets (in terms of official CO_2 equivalents above) associated with landfill gas power which they purchase.

State (California) Initiatives include the California Environmental Quality Act (CEQA) those of the California Energy Commission (CEC), California Air Resources Board (CARB) and Waste Board (CIWMB).

Local initiatives include rules in California Air districts.

Note A-4. Economic Factors--Valuing Emission Abatement with Electricity from Biogas.

What is the greenhouse gas abatement value? The valuations assigned to GHG abatement by states' PUC's were stated in earlier text. Many U. S. electric utilities are also presently addressing (or willing to address) global warming by projects to abate or offset fossil CO_2 carbon emissions. This is sometimes due to the PUC guidelines (examples: MA, WI, NY) but has often been voluntary. Some U.S. utilities have been willing to consider projects to accomplish GHG abatement at costs up to $10-20/ton fossil CO_2 carbon abated (or $2.75-5.50/ton fossil CO_2, in the U.S. European abatement and offset processes over twice these stated U. S. costs are under way). On the basis of lower cost U. S. GHG abatement, and knowing generation heat rates and the greenhouse potency of methane, valuations for methane abatement can be calculated. Example calculations summarized in Table 2 (next) result in GHG abatement values of $ 0.014 to $ 0.075/kWh for electricity from biogas.

What is the value of VOC abatement? California air rules typically entail cost (thus implied value) of $1.00 to $2.50 per pound of pollutant destroyed. Worth of VOC (air pollutant) abatement be calculated assuming values for landfill gas VOC content and heat rate. These calculations (also in Table 2) show values for air pollutant abatement that might range between 0.28 and 2.1 cents/kWh.

The total of these benefits' calculated value--per kWh generated--is $ 0.017 to 0.096/kWh. All calculations with their basis are presented in Table 2 (next page).

Note A-5. "Public Good" from Biogas-to-Electricity Emission Abatement.

Example calculated values of methane and VOC emission abatement (above) ranged from $0.017-0.096/kWh. These calculations indicate "public good" which accrues with the use of electricity from biogas. Several considerations arise in the evaluation of the degree of "public good"**:**

Some degree of methane and VOC abatement (see further discussion) will occur with LFG because of regulations anyhow, even without conversion to electricity. However the "public good" value per kWh will still exist for nearly all biogas conversion to electricity**.**

TABLE 2 ENVIRONMENTAL BENEFIT (EXTERNALITY) VALUATIONS IN SUPPORT OF BIOGAS-FUELED ELECTRIC POWER GENERATION

I. GREENHOUSE GAS (GHG) MITIGATION potential valuations: Range: 1.4 to 7.5 cents/kWh with assumptions below

VALUATION OF FOSSIL CO_2 CARBON ABATEMENT		Assumed mol ratio CH_4/CO_2 greenhouse potency	energy credit, \$/MCF CH_4 used (or \$/10^6 Btu)	Generation heat rate, Btu/kWh	Calculated greenhouse gas mitigation credit, cents/kWh
\$/ton CO2 carbon	**\$/ton CO2**				
\$ 10	\$ 2.75	9/1 (U. S. DOE 1605 b official value, 1996)	\$ 1.42	10,000	1.42 cents/kWh
\$ 10	\$ 2.75	9/1 (U. S. DOE 1605 b)	\$ 1.42	15,000	2.13
\$ 20	\$ 5.50	9/1 (U. S. DOE 1605 b)	\$ 2.86	10.000	2.86
\$ 20	\$ 5.50	9/1 (U. S. DOE 1605 b)	\$ 2.86	15,000	4.27
\$ 10	\$ 2.75	16/1 (Rodhe, 1990, Augenstein, 1990, 1992)	\$ 2.51	10,000	2.51_
\$ 10	\$ 2.75	16/1 (Rodhe, Augenstein,)	\$ 2.51	15,000	3.76s
\$ 20	\$ 5.50	16/1 (Rodhe, Augenstein,)	\$ 5.02	15,000	7.5 cents/kWh

II VOC EMISSION MITIGATION potential valuation: Range 0.28 to 2.1 cents /kWh with assumptions below

Valuation of VOC abatement, dollars/lb. VOC's mitigated	Assumed weight ratio of VOC's to biogas (ave M. W . 28)	energy credit, per \$/MCF or 10^6 Btu	Generation heat rate, Btu/kWh	Calculated VOC mitigation or "offset" credit, cents/kWh
\$ 1.00	0.0025 (= 0.25%)	\$ 0.28	10,000	0.28 cents
\$ 1.00	0.0025 (= 0.25%)	\$ 0.28	15,000	0.42 cents
\$ 1.00	0.005 (= 0.5%)	\$ 0.56	15.000	0.84 cents
2.50 (Typical Calif. cost, CARB)	0.0025 (= 0.25%)	\$ 0.70	10,000	0.70 cents
\$ 2.50 """"	0.0025 (= 0.25%)	\$ 0.70	15.000	1.05 cents
\$ 2.50	0.005 (= 0.5%)	\$ 1.40	15,000	2.1 cents

Total potential credit range, cents/ kWh by calculations above (GHG = 1.42 to 7.5) + (VOC = 0.28 to 2.1) = 1.7 to 9.6 cents/kWh

(incent1)

-Even with gas control regulations, methane and air pollutant mitigation is accomplished automatically by electricity generation, offsetting costs of abatement by other routes--thus there is still public good in terms of cost saving to the public (which in the end, directly or indirectly, bears nearly all abatement cost). In addition, regulations, even when they apply, are inefficient at abating emissions for several reasons.

(a) efficiency of "control only" landfill gas recovery systems without further measures to maximize gas recovery is only 50-90%

(b) there is inefficiency of rule driven biogas recovery for other technical reasons, e.g.**:**

i. Federal and California rules really address only VOC's in landfill gas. There exists no U.S. or California statutory authority to control methane emissions to the atmosphere per se (and, methane control is what offsets utility sector greenhouse CO_2). For landfill gas, VOC levels are low enough so that sites with potential to 5MWe or more (thus most sites) can escape methane emission control28.

ii Final federal clean air act rules exempt landfills below 2.7 million U. S. tons a priori from control; thus landfills below 2.7 million tons, containing about 40-50% of all U. S. waste will escape control unless other mechanisms can ensure recovery.

iii For California, a landfill surface concentration standard to drive control is sufficiently imprecise (i. e. for fugitive emission assessment) that large fractions (> half) of landfill gas may occur as well.29

iv. Manures (major sources of greenhouse gases) are exempt from gaseous emission controls

However with electric revenue and profits at stake, landfill and other biogas can be expected to be "scavenged" to maximize electric power generation from the biogas at given sites (this is amply substantiated by experience with landfill gas fueled electricity production under California's SO-4 contracts). Measurements, where carried out, have shown this "scavenging"

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28 This is supported in letter communication and documentation of Don Augenstein to Mark Najarian, then head of EPA clean air act implementation, March 21, 1994. Supportive information is published as well in the March 1994 proceedings (Augenstein, D. "Landfill Gas Control, Landfill Gas Regulations and Climate Change--some Practical Considerations") and March 1996 (S. Hill paper) proceedings of the Landfill Gas Division of the Solid Waste Association of North America.
29 See letter of Dr. Stanley Zison to James Behrman, Toxic Program Support Section, California Air Resources board, dated May 15, 1990. Also letters and documentation of Don Augenstein to William Schuldt, Yolo-Solano Air District, and Renaldo Crooks, California Air Resources Board, December 12, 1994. Both these communications make the point that measured surface gas concentration is far more the correlate of meteorology than fugitive emissions

to substantially decrease CH_4/VOC emission (Zison, 1990). Thus biogas use for electric generation increases public good from emission abatement.

All of the public good arguments are explicitly or implicitly reflected in federal and California programs and statutes. However the gas control (and thus public good) resulting from present regulation is at best partial. Additionally, economics for most biogas use are presently too poor to support current EPA and DOE biogas energy use initiatives that are important parts of the Climate Change Action Plan. For example the economics for gas use are presently poor enough that only about 20-25% of California landfill gas finds beneficial energy use. The balance is wasted, in large part by atmospheric emission.

Promotion of environmental benefits as discussed above, via GEC's and increased revenue, could help significantly toward offset of adverse effects of climate active gases for which the utility sector bears responsibility. These climate active gases are also of major federal and international concern. It also values local air quality benefits according to statute. In summary a sufficient sale price for electricity from biogas in the restructuring process via the GEC addresses these problems, and maximizes public good in terms of greenhouse gas and other emission abatement.

Note A-6. Landfill gas and manure biogas electric potential in California

California landfill gas electricity potential is estimated by prorating the national potential stated by EPRI or U.S. EPA (roughly 5000-7000MWe) according to population. This is valid given per-capita waste disposal and methane generation that is similar across the U.S.

For manure methane, in the reference of Whittier et. al., the gross potential in California is cited as 20 billion cubic feet per annum. Assuming 25-50% of this can be economically captured for electricity the electric potential from manure in California, at heat rate of 12,000 Btu/kWh, is about 50-100MWe.

Note A-7 Calculating "equivalent CO2 offsets" from biogas use.

The global warming potential (GWP) mitigated, or "CO_2 offset" from energy use of methane is the key benefit of the GEC. This CO_2 offset can be expressed in a relatively simple equation:

$MCO_2 = F \times CO_{2eq}$.

Where MCO_2 = Equivalent carbon dioxide mitigated (the "CO2" offset)

F = Fraction equivalent to (methane emission mitigated/methane used for energy).

CO_{2eq} is the carbon dioxide equivalent of methane (weight or volume--see below)

In many situations (as with methane from lagoons) F approaches 1. The value of F = 1 means that methane captured for energy reduces an equal amount of methane emission to the atmosphere. In the case of landfills, values for F depend on site factors. For large landfills, whose control could be presumed in any case, added mitigation (from methane "scavenging") with energy use may average closer to 25%; for smaller landfills the mitigation may be 50% and for smallest, without control, the mitigation approaches (i. e., F = 1.0) Values for F averaged over all landfills may be around 50%, (but it is noted that site-specific analytical determinations to enable exact values for F have been scarce and are technically demanding). Reasons for landfill control inefficiencies (thus that F is likely ≥ 0.5 overall) were discussed in note A-5.

Lower values for F result in lower values for MCO_2. However the CO_2 equivalence of methane by IPCC rules is conservatively low30 and higher potencies for methane are readily substantiated by straightforward calculations (evaluating radiative forcing over shorter time spans):

Source of calculation	Calculated CO_{2eq} of methane, weight/weight	Calculated $CO_{2\ eq}$ of methane, vol/vol
IPCC working value	24.5	9
Augenstein, 1992	41	15
"Instant" potency	68	25

Thus F can be below 1, but higher values of CO_{2eq} can equally well apply. These have opposing, canceling effects on MCO_2. A reasonable approach is suggested here to be use of conservative (low) IPCC values for CO_2 with assumption of complete abatement. These same rules (assumptions) are already applied in the U. S. Department of Energy 1605 (b) program for voluntary reporting of greenhouse gas abatement.

Another issue in calculating greenhouse gas abatement per kWh of electricity from biogas is thermal efficiency, which relates kWh to CO_{2eq} destroyed. However heat rate can vary; onsite measurements of heat rate can be difficult and uncertain. To avoid the intricacies of

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30IPCC integrates methane's radiative "greenhouse" forcing over 100 years. Augenstein (1992) assumes a timespan of 40 years. Methane, molecule for molecule, is about 25 times as potent as CO2 determining process-specific heat rates it is suggested that a heat rate of 10,000 Btu/kWh be stipulated for any CO_2 eq determination. This probably reflects well the heat rate that will obtain for the near term (present rates are closer to 12,000 Btu/kWh). As a lower number of Btu/kWh corresponds to lower CO_{2eq}, this stipulated efficiency is conservative in the CO2 mitigation it projects. Also, by adopting this fixed thermal efficiency in calculating CO_{2eq}, processes that are in actuality less efficient are penalized and efficient ones rewarded in the proposed approach (the desirable result)

In calculating cost-effectiveness of greenhouse gas abatement a further "accounting" issue is cost to attribute to abatement-i. e., should the cost be the GEC per unit MCO_2--or some other value? All REC costs (perhaps 2REC/kWh) could--conceivably--be deemed for (or charged to) greenhouse gas abatement. However biogas use gives not only greenhouse gas abatement but the other benefits in common with all renewables. For electricity from biogas, benefits aside from greenhouse gas abatement include (a) addressing stratospheric ozone depletion (b) domestic production (c) local economic benefits (d) sustainability, and (e) the abatement, for all biogas, of a very considerable degree of local air pollutant emission. Even though valuations are subjective, these justify at least one of the two RECs by the same reasoning applying to other renewables, leaving the other REC (from the GEC) as the incremental cost assignable to the greenhouse gas abatement.

Altogether, the above presents the basis for greenhouse gas abatement cost as incremental cost of the GEC, assigned to the fossil CO2 carbon offset as determined above. This is the basis selected for this proposal, and presented in the overview.

3. Implementation Questions

a. What is the Obligation?

a.1 How is "renewables generation" defined for purposes of qualifying for tradeable "renewables energy credits" (REC's) under this proposed program? Do existing and utility-owned renewable-resource generation qualify for Renewable Energy Credits?

Renewables generation is defined on a kWh basis, except that biogas kilowatts are given Greenhouse Environmental Credit in addition to the Renewable Energy Credit (REC) of other renewables. See AWEA for more detailed definitions of renewables. In addition to AWEA's definition, hydro might be included, but factors need to be addressed as noted in a.8

See AWEA--existing utility-owned renewables are included

a.2 *What are renewable energy credits? How do they relate to energy portfolio management?*

See AWEA or IEP. RECs represent a value assigned to one unit of energy production, one credit per kWh of production except for biogas which receives a greenhouse emission credit (provisionally, equal to another REC) as well as a renewable energy credit in this proposal.

A renewables purchase obligation would require each UDC (or any entity) selling electricity to retail (end-use) customers to be responsible for purchase and distribution of a pro rata share, constant statewide, of renewable power or corresponding RECs for renewable power. The entity's purchase obligation for renewable power (or equivalent REC's) is expressed as a percentage of total retail sales of electricity. The purchase obligation could include as well a pro rata share of banded solid fuel biomass, and pre-commercial technologies (including manure biogas) as in proposals of others including the present proposal, IEP, the CEC or AWEA.

a.3 *How is a diversity of renewables encouraged?*

Electricity from biogas is effectively favored. However it is proposed that its allocation be expanded so that all electricity from biogas is accommodated to maximize cost-effective climate benefits, without reducing the allocation for other renewables . By expanding the REC/GEC allocation in this way, the generation from, and diversity of, renewables would be essentially unchanged from that would otherwise exist absent biogas to electricity. Otherwise see IEP or AWEA

a.4 Are currently high-cost technologies or pre-commercial technologies fostered by this program?

Yes. Much electricity from biogas is high cost (in terms of electric power cost alone, without considering climate benefit). This proposal facilitates its use by factoring in the climate benefits through the GEC.

This proposal additionally concurs with AWEA and IEP on banding of solid-fuel biomass facilities. It also agrees with the CEC staff proposal proposing the tier approach. In the CEC tier approach, technologies starting their transition to full commercial deployment receive higher revenue than renewables developed to greater degrees of commercial deployment (like wind, geothermal, etc.). The higher revenue is achieved through mechanisms such as increased REC's per unit of power generated, or perhaps other mechanisms (to be more fully developed).

A specific issue is that manure biogas is sufficiently far from wide commercial deployment so that it should be placed in a higher revenue tier, possibly by more than one GEC or REC per kWh. If a limited amount of generation (say, 10MWe) is in a higher revenue tier to assist the development to "full-commercial" status it should not be subject to the cost-effectiveness standard.

a.5 How is renewable self-generation handled? Is self-generated renewable energy eligible for Renewable Energy Credits (REC's) or for other means of support?

Renewable self-generation, as with grid-delivered, does provide the benefits of renewables. However renewable self-generation already presumably nets a premium in "backing out" higher cost retail electricity-and, perhaps, any competition transition charge. It is also harder to track, presenting administrative difficulty. It is in addition already economical (or it would presumably not be done). On all these bases it is suggested that renewable biogas self-generation might be excluded or perhaps (though it would be administratively intricate) should receive lesser credit perhaps only the REC per kWh.

a.6 How are hybrid fossil-fuel/renewable facilities handled?

The REC's assigned per kWh of output should represent, as well as possible, the fraction fueled by, thus attributable to, the renewable resource. Thus if the renewable fuel thermal energy fraction is 75% each kWh would represent 0.75 REC. In the case of biogas the GEC's would be prorated as well on biogas heating value. (This issue is quite pertinent because of cofiring progress made and applied both with landfill gas and wood/fossil. However the approach may also become administratively complex during fossil/biomass fueling ratio changes, etc.)

a.7 Does out-of-state generation qualify for REC's? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

The treatment of GEC's and REC's for biogas is as with REC's for other renewables--out of state generation would appear eligible under the commerce clause, and restrictions would not appear possible.

a.8 If hydro is included, how are practical issues associated with hydropower handled?

Hydro may very likely not be included. (AWEA or IEP provide more discussion). However if hydro is included as advocated in some proposals then it may be necessary to separate its band from other renewables to avoid complexities and untoward effects of year-to-year hydro variation on levels of other renewables' use. Cost equity needs somehow to be achieved between hydro and other renewables, particularly so that low-cost hydro does not provide an avenue to "back out" use of other renewables. To avoid this and yet other complexities it may also be most desirable to restrict eligible hydro to environmentally mitigated, or new (online since (say) 1/95 (SMUD approach). Hydro advocates need to offer some better solutions if hydro is to be accepted.

a.9 How are utility-owned distributed renewables handled? Does the proposal permit or prohibit REC's being awarded to distributed renewable power not sold through the power exchange? How does the proposal guard against self-dealing or cross-subsidization? For example does the proposal permit REC's to accrue to applications that may involve the cross-subsidization of generation with T&D savings, or vice-versa?

AWEA or IEP approaches are valid for handling of utility-owned distributed renewables.

There is likely T&D saving with electricity from landfill gas and digester gas. Saving accrues from the fact that these are nearly all adjacent to population centers that use the electricity. This is likely a "bonus" that will to some extent improve overall system efficiency and lower cost. How much of a bonus it comprises cannot be estimated at this time.

a.10 What is the level of the requirement? How does this level relate to the level of renewables from 1990 to the present? Does the level of the requirement increase over time, and if so, at what rate?

A base level of 10% renewably based electricity as of the start date is suggested (identical to AWEA proposal), <u>plus</u> however much electricity may be generated from biogas. A level of 10% is slightly below the maximum renewables output that was achieved (in 1993--see AWEA, citing statistics provided by CEC) and should result in adequate competition. An increase of 0.2% per year as the renewable fraction of the total generation portfolio is suggested (as with AWEA). However the annual increase rate would be set under terms of any proposal to which this proposal is an adjunct.

a.11 Describe how, if at all, the compliance obligation adjusts during a transition period.

The compliance obligation may need legislation developed to bring utilities not under CPUC jurisdiction under the obligation. See answer to next question.

a.12 Does the proposal provide a uniform requirement for all electric providers, including utilities, on a statewide basis?

It is anticipated here that initially, all utilities/UDC's subject to the jurisdiction of the CPUC would purchase power or REC's sufficient to attain the renewables requirement. Eventually the obligation would apply to all entities selling power to end-users. See also a. 2. Legislation may be required to bring the entities other than IOU's in.

a.13 What is the time-horizon for the program?

(Note: Financing of new renewables facilities, which increases competition, may be contingent on an expectation that a market for renewable power will exist for an extended period of time)

Starting as soon as possible. The portfolio requirement should at minimum continue for a long enough period for renewable projects to obtain financing, at least exceeding 10 years. We would propose that it continue indefinitely, to the extent a credit continues to be justified by environmental and conservation benefits, and so long as renewably-based generation costs are in excess of fossil-based.

a.14 Is the requirement established on a percentage of megawatts or percentage of megawatt hours basis?

Megawatt hours, since benefits are proportional to megawatt-hours generated. As Greenhouse Environmental Credits are envisioned an added GEC + REC purchase obligation would be as a pro rata share of whatever electricity megawatts are generated from biogas.

a.15 Does the proposal establish floors for certain technology types? What is the rationale for a technology floor, if proposed?

Floors are advocated here for solid fuel biomass, and pre-commercial technologies. The floor for solid-fuel biomass assures continuation of desirable levels; the floor for the precommercial technologies helps their development to commercial status. In the case of biogas, a GEC is proposed in addition to an REC, with initial effect that a kWh receives an REC twice that for other technologies. This treatment for biogas has effects similar to a floor, but greater flexibility in promoting use and environmental benefits and is based on the additional climate benefits.

b. Where is the obligation to comply?

b.1 On whom is the requirement applied? Is the requirement applied only to entities under the CPUC's jurisdiction, or is it applied statewide?

It seems most practical that the requirement should be imposed on <u>all</u> utilities or other entities selling electricity at retail (i. e. to end users), including municipally owned and others not now regulated. Legislation is required to accomplish this.

b.2 Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences? What is the status of entities not under CPUC jurisdiction in this program?

See AWEA, for discussion of treatment of regulated vs. unregulated retail providers. Entities not under CPUC jurisdiction will remain so until legislation enables their control.

b. 3 What is the penalty for non-compliance? Should this penalty be interpreted as a cost cap for this program?

Other proposals would fix the penalty in terms of REC shortfall, which would in turn effectively fix penalty for the GEC as well.

b.4   How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

See AWEA

b.5 What provisions and flexibility are there in compliance?

For administrative purposes and those of evaluating compliance, the GEC would be treated as its REC equivalent. Otherwise this question is not applicable (N.A.).

b.6 How does the program ensure that the policy and its costs are non-bypassable, such as the CTC or public goods surcharge?

See AWEA

c. How are Renewable Energy Credits Initially Allocated?

c.1 How are REC's generated from existing renewable facilities (QF's and utility-owned) initially allocated? What impact does the initial allocation have on whether a vigorous market for REC's, characterized by many buyers and sellers, forms?

See AWEA, c.1. This would apply to REC's resulting from GEC's as well.

c.2 What is the relationship of the allocation of the renewable energy credits and the CTC or Public Goods surcharge? Will REC's accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid and avoid the CTC?

N.A.

c.3 If customers or ratepayers are initially allocated REC's, how are the credits administered?

N.A.

c.4 How would the proposed Renewable Energy Credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make them more or less cost-effective to ratepayers?

See AWEA.

c.5 How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

The overall intent of this proposal is to maximize greenhouse gas abatement in the most cost-effective manner possible (and concurrently to limit "windfall" profits) To address "windfalls" and closely-related problems we suggest several measures:

Earlier ongoing projects should be "grandfathered" to their existing contracts as long as operational under contracts giving higher than market prices (market prices being the averaged statewide renewable sale prices to the pool, counting REC's). Projects while grandfathered receive no GEC's. After expiration of QF contracts the GEC could be set equal to half of an REC, to limit profits.

A related issue occurs in situations where costs are low, controls would be expected, and abatement would be reasonably expected through energy uses in any case. This might, for example, be the case with larger landfills (Note A-7 discusses this). One such specific case is that of landfills likely to require control by federal standards (based on prescribed VOC emission measurements). A size criterion--such as at 5 million tons--could apply where energy uses receive half, rather than one GEC per kWh. (The transition from applicability of one, to applicability of one half GEC/kWh should be staged such that the electric revenue does not dip, or rises slowly with this transition.)

To assure that the desired greenhouse gas abatement is maximized an additional measure is proposed:

-To receive the GEC, sufficient generating or other equipment be in place so all recoverable biogas is used or abated. This can be evidenced by biogas-fuel-limited operation of energy equipment[31] (This condition would provide strong incentive for efficient methane recovery and thus the greenhouse emission minimization which is the major corollary objective of electricity from biogas.)

Regarding any remaining "windfalls" occurring after these measures to limit them:

-We note that benefits accruing from the increased GEC would accrue largely to entities managing the wastes which generate methane. In cases of both municipal solid waste, and wastewater, management, revenue benefits of electricity generation return in very large part to the same base of ratepayers as pay for electric power.

c.6 Does the proposal potentially increase the value of utility owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

See AWEA

d. How is the Program Administered?

d.1 What agency certifies the REC's, and what does the certification process entail?

The CEC appears a likely candidate. Most relevant for this proposal, the agency certifying REC's would certify GEC's as well.

d.2 What mechanisms are proposed for trading of REC's? How do the trading mechanisms relate to the initial allocation of REC's?

See AWEA or other proposals. However a Greenhouse Emission Credit (GEC) is envisioned as trading at its equivalent REC value, and otherwise in exactly the same fashion as an REC.

d.3 What mechanisms are envisioned for program oversight and mid-course corrections?

N. A. This proposal is intended as an adjunct to other proposals in which those issues would be addressed. Adjustments to the GEC approach should be readily possible in conjunction to adjustments to the REC approach.

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31 Modular biogas-fueled IC engine capacity (or, soon, fuel cells) can be installed to meet this condition; alternatively other energy uses, or supplemental flares can assure minimum fugitive emission as well but energy uses with corresponding revenues are considered to provide maximum incentive for abatement.

d.4 What agency monitors and enforces compliance with the program, and how is it carried out?

N. A. This proposal is intended as an adjunct to other proposals where such issues would be addressed. However, note that the agency would monitor the administration of electricity from biogas and assure that requirements associated with GEC's as well as REC's are met.

e. Cost Related Issues

e.1 What are the costs associated with the program, and who pays?

Two foreseeable cost components, are the GEC/REC cost, and the administrative cost. These are passed through to the ultimate electricity consumer. At this point, the REC value and the administrative costs are uncertain. However a "rough cut" is attempted here:

The GEC/kWh may end up (on average) in the neighborhood of $0.02/kWh. Given this the extra cost per biogas kWh would be (to the precision with which such estimates can be made) perhaps $ 0.04/kWh. The resulting GEC value of $0.02/kWh is incidentally, a low end valuation of the greenhouse gas abatement, and a low-end total for abatement of all emissions through biogas use (see Table 2, Note A-4)

To the extent that estimates can be made, landfill biogas based generation in California may rise to 500MWe from 150MWe in response to this price, and manure biogas generation coming online in response to price may be 50MWe (bases for estimates are presented in Note A-6). Sewage digester biogas based generation would also rise, to 50MWe. At 90% service factor, and assuming that the GEC applies to all electricity from biogas, the estimate of incremental cost due to GEC alone can be calculated as $ 75 million:

600MWe x $17/MWe(ave) x 8760hr/yr x 0.85 service factor = $75,949,200 (≈$75 million)

Administrative costs should be small as an increment, possibly the order of a few hundred thousand per year inasmuch as the GEC would be treated in parallel with the REC.

e.2 What cost-containment measures, if any, are provided?

A cost limit is inherent in adjustment of the GEC's as discussed in C-5 above. Several other factors inherently limiting cost of the obligation, as noted in the overview are competitive determination of GEC value (through the REC) and the size of the resource eligible for the GEC. Yet another factor limiting costs is the cost effectiveness standard imposed in terms of climate active gas abatement.

e.3 If the program utilizes floors for certain technology types, what are the implications in terms of costs and benefits?

The allocation of the GEC has effects somewhat akin to a floor, and results in abatement of climate active gas emissions from a source where it can be accomplished with maximum cost-effectiveness.

Another higher floor may be applied for technologies in earlier stages of development such as electricity from animal manures.

e.4 Will implementation lead to cost-shifting between consumers or regions of the state?

Not anticipated

e.5 How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities?

Generation of electricity from biogas would be favored over other renewables, by monetary value of the GEC/kWh (over the balance of non-renewable generation). However keeping the REC allocation (as percent of total power generation) for other renewables technologies constant, means competition between other renewables occurs essentially as it would without electricity from biogas. On the second part of the question, existing renewables facilities and potential new facilities would compete together for the same "customer" base.

e.6 What implications if any does the proposal have in defining the roles of the LDC and of competitive suppliers of electricity?

N.A

e.7 What is the consistency of this proposal in relation to cost-related guidance provided by the CPUC Roadmap?

N.A.

f. How does the Program fit with Other Aspects of Electric Industry Reform?

f.1 Is the system compatible with the existence of an independent system operator? A Power Exchange? A Direct Access Market? Is the proposal consistent with the Commission's vision of the role of the Power Exchange and ISO?

Compatibility with all of the above should be as with the approach using the REC alone.

f.2 Is the proposal dependent in any way on the power exchange or ISO? If so, are there any additional protocols necessary?

N.A.

f.3 Does the proposal involve conflicts of interest of interest between distribution and competitive retail service? If so, how are they resolved?

See AWEA

f.4 How does the program avoid conflicts of jurisdiction between state and federal levels?

No issue is envisioned that would not otherwise occur with a program based on REC's alone.

f.5 What is the relationship between the proposal and direct access "green marketing"?

The relationship would be the same as with other renewables proposals. Green purchasers may electively buy power from biogas (example was given in the text).

f.6 What is the relationship between the proposal and Performance Based Ratemaking (PBR)? Does the proposal place REC's under PBR or exclude REC's from PBR?

The UDC's (or other entities responsible for purchase of renewables or REC's) should not be financially penalized for swings or variations in the RECs or GEC precursors which they are mandated to purchase. Inasmuch as mandated for societal benefits, (i.e. public purpose) these costs should be passed through, directly or indirectly, to electricity end-users.

f.7 Does the program create any potential market power problems involving the generation market or REC's?

None foreseen

f.8 How does the proposal relate to any consumer protection or consumer education efforts? For example:

a. Rules for new entrants: Does the proposal require any licensing requirements for new entrants? Should compliance with the minimum renewables requirement be a condition of selling power at the retail level?

Consumer education: does the proposal require any consumer education? For example how does the proposal protect consumers from "green marketing" programs where marketers collect twice--once for credit sales and once for "green" power sales thereby not increasing total green power? This could entail, e.g., disclosure requirements to inform consumers about the amount of renewable green power they are purchasing that are supported by REC's or statements regarding price stability or price risk of the seller's resource portfolio. Would REC's accrue to utilities from green pricing programs where utilities have unique customer information and access?

Power sold at the retail level, by any seller, would need to be in compliance with the standard that develops. We note that consumer education issues should be essentially the same as with REC's

f.9 How if at all does the proposal relate to the RD&D programs funded by the public goods surcharge?

The proposal supports "bands" that would facilitate pre-commercial technologies. One specifically, is biogas from manure.

f.10 How, if at all, does the program relate to the energy efficiency programs funded by the public good charge?

N.A.

f.11 How does this proposal affect the CEQA compliance work recently initiated by the CPUC?

This proposal addresses what should be a central issue of utmost importance in the CEQA compliance work**:** the net emission of climate active gases by the utility sector. It also addresses air quality and other environmental benefits. It also incidentally, addresses emissions of a gas, methane , which participates in destruction of stratospheric ozone.

g. Legislative Requirements

g.1. Can the CPUC implement this program by itself, or is legislation required? What would the legislative requirement be?

It will only be stated here that the needs should be very similar to those involving an REC alone.

g.2. What steps are needed to implement the program and how long would it take? How does this implementation timing relate to the CPUC's 1998 implementation goal?

Probably close to the time that would be required to initiate a program based on REC's alone. We suggest (as does AWEA) that implementation be accelerated if possible--see AWEA.

4. Positions of the Parties: In favor/neutral/oppose

Comments of the CPUC's Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

DRA/UCAN/IPP conditionally oppose this proposal because:

1. It adds unnecessary complexity. Biogas could participate in the AWEA-proposed biomass set-aside.

2. If, however, the Commission or the legislature approve a dual credit approach for biogas, DRA believes that it should be in the form of pilot implementation and that the biogas resources should receive general renewable credits, rather than biomass credits under the AWEA plan.

3. The pilot should last three years. Its costs and benefits should then be evaluated. The program may be renewed if the implementing agency is satisfied with the costs and benefits of the program. Preferrably, the pilot should be folded into any biomass set-aside that may exist.

4. The pilot program must not cause the rate cap to be exceeded.

Comments of CBEA

CONDITIONALLY OPPOSE. This partial plan proposes to give biogas-fueled electric generators double value credits based on the additional value of greenhouse gas abatement and the extra cost of biogas generation as compared to other renewable resources. Greenhouse gas reduction is important , but is a value of landfill diversion resulting from biomass plant fuel collection as well. Biomass fuel does not go into any landfill, and biomass has the waste management benefit over biogass. Biogas-fueled generation does not appear to offer any unique benefit so as to be deserving of double credit. Witout double credit, biogas is a beneficial renewable resource.

Comments of AWEA

Concur with CBEA. Biogas generation is largely landfill gas fueled. Landfills are required to have gas collections installed as a requirement of their permits, and the cost of these systems is borne by the landfill tipping fees. Therefore the fuel and its collection for biogas generation is free, and is an easy to handle gas. Such generation should therefore be significantly less expensive than solid-fuel biomass, which requires very costly fuel collection, processing, transportation, and handling, and thus biogas generation should be able to compete within the RPS with other renewables without a double credit.

Comments of Some Surcharge/Production Credit Proposers

(Note: Where Surcharge/Production Credit Proposal supporters' names appear independently in these "Position of Parties" subsections, their position is not included in the following position statement made on behalf of the remaining supporters.)

Neutral

1. Increases cost unnecessarily for customers: Targeting a single environmental contribution (reducing methane emissions), claiming entitlement to additional program funds, then adding special credit purchase requirements is unnecessary and exorbitant in addition to an MRPR.

2. Gives unfair advantage to biogas over other renewables: Doubling credits makes biogas plants first choice for buyers over competition until requirement is met.

3. Needs funding as RD&D: If this technology is truly pre-commercial, as the proposal description indicates, the CPUC proposed RD&D funding is the appropriate mechanism to support this proposal or possibly special legislation is the necessary vehicle.

Comments of the Union of Concerned Scientists

Oppose.
Pros: Accounts for greenhouse gas mitigation of biogas.

Cons: Does not systematically account for full range of externalities. Technology specific: does not offer same valuation for other technologies which mitigate release of greenhouse gases or offer other unique public benefits.

Comments of Southern California Edison

This proposal can be an add-on to any of the MRPR proposals. Its key feature is that it doubles the value of a kwh generated from biogas combustion. It also complicates the program. While turning biogas into electricity undoubtedly has its environmental benefits, it is questionable whether they should receive twice the credits of other renewable technologies and whether the additional program administration cost and complexity is justified.

Comments of Roy Sharp

I am involved in EPA's AgStar Program and speak for small biogas digester operators. For 15 years electricity from manure biogas has met our needs for 27,000 head on our swine operations, with excess sold to the grid.

The BWG proposal helps farmer's interests in dealing with odors and emissions. Energy use of biogas is a major part of the Climate Change Action Plan, and greenhouse gas reduction is strongly endorsed by utilities. All these benefits are appropriate to value monetarily in the electricity generated, under California utility code. The BWG proposal provides a win for everyone including the public.

Comments of John Palmer, Sacramento County Energy Manager

Sacramento County is interested in developing its renewable power resources to the extent that it is economically possible. There are substantial sources of landfill gas within Sacramento County that may be economic for us to develop with sufficient electrical energy revenues. We support the biogas group proposal which provides a revenue incentive that will help us develop our renewable resources as well as help the environment by preventing methane emissions.

Comments of SoCAL Gas

OPPOSE - This adjunct proposal tries to establish that biogas qualifies for special treatment as a renewable resource because it could play a major role in reducing methane gas, a major greenhouse gas and a contributor to global warming. It calls for a greenhouse environmental credit valued at twice the regular renewable energy credit. The proposal also states it should qualify for a higher subsidy because it is an emerging technology. This is an example of how costs to consumers are disregarded in favor of carving out a secure market for an expensive technology.

Comments of SDG&E

Oppose:

- No cost limitation.
- Unequal cost burden on consumers. Penalizes SDG&E's customers for not having previously been subjected to more high-priced ISO4s.
- Implements double subsidies above already-subsidized payments to existing biogas developers in form of RECs/GECs. Consumers would pay additional $47 million annually to existing landfill developers.
- Since this is a 12% MRPR proposal, the statewide cost to consumers would be $600 million annually assuming a REC value of 2 cents.
- Administratively burdensome and complex.

Comments of Biogas/Climate Active Gas Working Group on Their Own Proposal

This proposal points out that the California electricity sector can cost-effectively mitigate a major source of greenhouse gas emissions, while simultaneously generating a moderate share of California's renewable electricity. Facilitating electricity from biogas provides a bargain for ratepayers and the public in terms of greenhouse gas abatement, since it can offset a significant fraction of fossil CO_2 emission by the electricity sector at low cost.

Comments PG&E

PG&E does not believe that special recognition should be given to any particular renewable technology within an RPS or a surcharge methodology. It is difficult to determine exact preferences for any given type of renewable, since all provide different environmental benefits. Moreover, the weighting given to these benefits is always partially subjective and changeable over time.

B. EMERGING RENEWABLE TECHNOLOGIES COMMERCIALIZATION PATHWAY

Submitted by the California Solar Energy Industries Association (CalSEIA), Solar Energy Industries Association (SEIA), the Energy Technology Development Division (ETDD) of the California Energy Commission, and the Natural Resources Defense Council (NRDC)

1. Interpretation of Commission's Goals and Rationale for Strategy

This proposal focuses on the key issues of resource diversity and the continuing development of additional renewable resources that the Commission's December 20, 1995 decision emphasized. In that decision, the CPUC reaffirmed that they are "**committed to establishing restructuring policies which maintain California's resource diversity for existing resources as well as encourage(ing) development of new renewable resources**". Regarding the importance of having a diverse number of renewable resources, the Commission further stated that "**it may be appropriate to establish floors for certain technology types, in order to maintain the diversity of our renewable resources" and that "encouraging resource diversity through the development of new resources is derived from Sections 701.1 and 701.3".**

Section 701.1 specifies that renewable energy resources include technologies utilizing wind, solar, biomass and geothermal energy. Maintaining and increasing California's resource diversity should, therefore, include a means for both preserving and encouraging the development of generation technologies and facilities in at least these four resource areas.

Unfortunately, none of the full implementation strategies being presented to the CPUC by the Renewables Working Group will adequately provide for this resource diversity. This is because all of the other proposed strategies are structured to exclusively favor existing renewable generating facilities and/or the technologies and resources they represent to the exclusion of newer renewable technologies and resources. None of the other proposals include a component or pathway through which newer technologies, such as photovoltaics, dish/stirling solar thermal electric or advanced biogas technologies, for example, could participate and fairly compete with existing technologies. These new or "emerging" technologies would augment California's resource diversity in critical and under-represented resource areas, such as solar. Solar technologies, for instance, are on a downward price trend, and this proposal would accelerate market transformation of this highly promising technology.

However, emerging technologies are economically precluded from any participation in the renewable strategies as proposed because their current generation costs are not, as of yet, able to compete with existing facilities such as wind, biomass and geothermal. Our proposal seeks to focus attention on this critical gap by providing for the commercialization of emerging renewable technologies. Four approaches, utilizing either a purchase requirement or a surcharge mechanism, and/or linking to RD&D or energy efficiency programs as they are defined in the restructuring process, are proposed for bridging this gap.

2. Program Overview and Description

a. A Pathway for Emerging Technologies: The Missing Link

The CPUC has clearly recognized the need for and desirability of providing support for California's renewable resources and for the RD&D process to develop new generation technologies. The development of any generation technology, however, is a continuum from research to development to demonstration to commercialization. The first three phases of this process can be maintained through the proposed use of a surcharge to continue funding these functions in a restructured electric services industry. The commercialization phase has not yet been clearly addressed by either the RD&D or Renewables Working Groups. Most of the implementation proposals from the Renewables Working Group focus on preserving the 5,000 MW of existing renewable generating capacity representing technologies that are largely commercialized, i.e. those whose current generation costs of 5 to 8 cents per kWh have been dramatically reduced from what their generation costs were when they emerged from RD&D years or decades ago. In many cases these cost reductions were achieved primarily through Standard Offer contracts, tax credits, or other publicly funded market creation activities.

New, emerging, solar and other electricity-generating technologies presently in the early or middle stages of the commercialization process have generation costs which are currently higher than this 5 to 8 cent range. While many of these emerging renewable technologies can be expected to reach generation costs comparable with the well-established renewables over time, the availability of small, but critical, markets for these technologies in their early stages are essential to the price reductions that come with completion of the commercialization process. The other implementation proposals, by focusing exclusively on minimizing projected program costs, and on preserving existing renewable generating capacity, would require these emerging technologies to compete with well-commercialized technologies, such as wind and geothermal. The Renewables Portfolio Standard proposal submitted by the wind, biomass and geothermal industries implicitly recognizes that solid fuel biomass, for example, cannot currently compete with wind or geothermal and must, therefore, have its own special type of credit and purchase requirement. If solid fuel biomass, with over 1,000 MW of installed capacity, is not yet fully commercialized, emerging technologies, with at most tens of MWs of previous installations, cannot be expected to compete directly with fully-commercialized technologies today.

The pathway outlined in this proposal introduces a commercialization component which is missing from the other proposals. This proposal outlines means of creating small, early markets, which would not add significantly to the overall cost of a renewables strategy. This proposal would create demand for approximately 200 MW of new generation facilities for selected emerging renewable technologies. These small new markets are less than 5% of the capacity of existing renewable generation and 0.2% of total generation and would be implemented over several years. The monies allocated to emerging technologies would ensure that cost reduction goals would be fostered through competitive market mechanisms, and would preserve California's role as the world leader in the development of renewable technologies such as solar energy.

There are several approaches that can be taken to bridge this commercialization gap. This proposal focuses on the two implementation strategies with the most supporters by providing suggested modifications to the purchase requirement-type mechanism proposed by the wind, biomass and geothermal industries, and the surcharge-type approach proposed by the Environmental Defense Fund and the investor-owned utilities.**.** The proposal also outlines a means of working within the Energy Efficiency and RD&D program structures**.** Any mechanism the Commission might choose to adopt, however, could be structured to provide an emerging technologies pathway. Regardless of which implementation strategy the CPUC ultimately selects, some provision for the needs of emerging technologies is crucial if valuable technological and resource additions to our renewables mix are to be advanced. We urge the CPUC to recognize that this is a critical component of the effort to ensure meaningful resource diversity and new resource development.

b. Modifying the Proposed Renewables Portfolio Standard Approach

The Renewables Portfolio Standard (RPS) strategy put forward by AWEA and others is a good example of a market-based approach to preserving existing renewable generation facilities. Our modifications of this strategy to include a role for emerging technologies are as follows:

New Technologies Band

One additional band, called the Emerging Technologies Band, would be created for all new renewable technologies that the state wishes to encourage. This band would be approximately 0.2% of generation in size, which equates to 500 GWh per year or 225 MW at a 25% capacity factor. Electricity generated by technologies in this band would receive Emerging Technology Credits (ETC). Like the proposed Biomass Energy Credits (BEC) of the RPS approach, the ETCs would be distinct from the general RECs and would constitute a separate purchase requirement. Unlike the BECs, they would not sunset after five years, since the need for a commercialization pathway for new technologies would continue for an indeterminate amount of time.

Technology Selection Based On Defined Policy Goals

The state would establish certain specific and well-defined policy goals for the inclusion of technologies in this band. Such goals, for example, might include the development and preservation of renewable industries which create employment in California and in which California is the industry leader, which reduce greenhouse gases such as methane and carbon dioxide or other air pollutants, which require commercialization activities in order to reduce costs, or which provide the benefits of distributed generation. It is expected that technologies such as photovoltaics, dish/stirling solar, central receiver solar, and biogas from anaerobic digestion or pyrolysis of solid waste would be among those technologies initially included in this band.

Credit Multipliers

To provide fair competition between technologies at different points in their commercialization process and, therefore, at substantially different generation costs, and/or to stimulate select technologies or applications such as distributed generation, the state could establish credit multipliers for technologies in this band. Thus, certain technologies could, for at least a limited time, receive more credits than others per MWh generated to compensate for their currently higher generation costs. These multipliers would be adjusted over time in response to actual or predicted reductions in generation costs. Credit multipliers do not increase the total cost of compliance, but rather affect the amount of electricity covered by the program.

Administration

The CPUC, CEC or other state agency, in consultation with an advisory committee composed of industry representatives and other stakeholders involved with these new technologies, would periodically determine the technologies eligible for inclusion in this band and establish appropriate credit multipliers. The state could also ensure that selected technologies deliver on the anticipated price reductions that inclusion in this band should permit by adjusting the value of such credit multipliers over time. The overarching priority is for each technology to reduce generation costs to the point where they can compete in the other, larger bands of the portfolio, and ultimately in the open market.

Ramping Up The Supply Of Energy Technology Credits

Recognizing that this band would contain new technologies and that virtually all of the supply of ETCs will come from new plant construction, a provision for ramping up electricity production from plants in this band should be included. The proposers suggest phasing in new production within this band at the rate of perhaps 0.05% of generation per year over a four year period.

Capping The Cost Of Compliance

A shortage of credits to fill the purchase requirement could result in higher than projected credit prices. This is a risk for all bands in a market oriented approach, but especially for an Emerging Technology Band. One solution is to set a maximum price for traded ETCs and thereby provide a cap on the maximum cost of compliance. The credit price cap would be set at a level approximately 25 to 50% higher than the expected market value of these ETCs, for example 12 to 15 cents per kWh for ETCs with a projected value of 10 cents. In order to make such a cap work efficiently, and to provide a self-correcting mechanism to avoid continuing shortages of the credit supply which would cause credit prices to repeatedly reach such a cap, the state could become a "market maker". In the securities markets, a market maker is recognized as necessary to provide order and stability. For example, in the event of a shortage of ETCs, the state, as market maker, would sell ETCs at the cap price in order for purchasers to fulfill their purchase requirements. The funds collected by the state from such sales would be used, through a competitive process of production credits or grants, to stimulate and accelerate the construction of new generating facilities, thereby alleviating future credit shortages.

Cost Of The Emerging Technologies Band

All market-based mechanisms share the common trait that the amount of the commodity is known, but the cost is not. The amount of electricity included in the Emerging Technology Band at 0.2% of total California generation is approximately 500,000 MWh per year. Our best estimate is that an ETC would initially trade at approximately 10 cents per kWh given the early commercial stage of emerging technologies. This would give a projected annual cost of $50 million for compliance. The cost could vary depending on the rapidity of generation cost reductions under this approach.

c. Modifying the Surcharge Approach

The Surcharge Distributed as a Production Credit approach proposed by the Environmental Defense Fund and others would require very little modification to accommodate emerging technologies.

Delineate A Portion Of The Surcharge For Emerging Technologies

The Surcharge proposal does not specify the amount of funds that would be generated by such a surcharge, however 1% of 1994 revenues from IOU electric sales would produce approximately $209 million per year. To create markets of approximately 200 MW in size for emerging renewable technologies, as estimated above for the RPS approach, would require an ongoing allocation of approximately $50 million per year. Emerging technology manufacturers have indicated that such an investment would significantly impact the downward price trend of these technologies.

The Surcharge proponents propose to provide production credits to selected projects for a term of 10 years. However, given that under their proposal a surcharge might only be in place between 1998-2000, funds could not be awarded in the year they are collected, but rather most of the funds would be “banked" to ensure that the full 10 year credit obligation could be met if the program were to be terminated in less than 10 years. These banked funds could conceivably earn interest while being held, thus further complicating the calculation regarding the amount of 10 year production contracts able to be awarded in any given year.

To fund 200 MW of emerging renewables would require that portion of the surcharge funds generated which, with interest on monies held in reserve, would total approximately $50 million worth of projects per year for ten years. As with the proposed RPS modifications presented above, the 200 MW of generation capacity could be phased in over 4 to 5 years, yielding the benefit of increased interest on retained funds in early years, thereby reducing the overall cost of the commitment. Once the financial variables were fixed, and the exact proportion of the surcharge necessary to fund 200 MW of emerging technology projects is established, the Surcharge approach could be easily modified to set aside some portion of the surcharge for emerging renewable technologies auctions, separate from the auctions for all well-established renewables.

Administration

The state agency administering the program would select the emerging technologies eligible to compete. The administrator might also need to make further groupings among these technologies so that those emerging technologies at different points in the commercialization process would not be asked to unfairly bid against each other if they have significantly different generation costs. This could be readily accomplished by separate credit auctions for technologies at approximately similar generation costs.

d. Add a Commercialization Component to RD&D Programs

Commercialization activities are a logical extension of research, development, and demonstration programs. When a technology emerges from the demonstration phase of RD&D, markets must be found which will further incentivize production and material cost reductions, design improvements, and will engender economies of scale. While commercialization has, at best, been a marginal component of prior state or ratepayer funded

RD&D programs, an opportunity now exists to structure an RDD&C continuum which bridges the gap between traditional RD&D and fully commercialized technologies.

Include Additional Funds In Rd&D Budgets Which Will Target Commercialization Of Emerging Technologies

As in the methods outlined above, adding funds to RD&D for the specific purpose of commercializing new technologies such that approximately 200 MW of new capacity could be built would require an ongoing allocation of approximately $50 million per year for ten years. The mechanism for allocating these funds could be identical to the surcharge approach to funding commercialization activities outlined above, utilizing competitive market mechanisms to ensure that competition would force price reductions over time, eventually leading to competition in open bulk power markets.

Administration

Again, as in the surcharge approach, the state or other agency administering the program would identify the emerging technologies eligible to compete. Similarly, the agency could group technologies in similar cost ranges together to compete for available funds in order to encourage cost effectiveness within technology sectors.

e. Utilize New Energy Efficiency Funds to Buy Down the Cost of Distributed Renewables

From both the utility's and the end user's perspectives, energy savings from distributed renewables situated on the customer side of the meter are indistinguishable from traditional energy efficiency measures, such as energy efficient lighting, for example. Aggressive commercialization of promising emerging technologies is the only means of surmounting the last remaining hurdle preventing the increased use of renewables: higher first cost. Perhaps the best example of distributed renewables is photovoltaic (PV) technology. The PV industry has long viewed the locational siting capabilities of PV equipment as one of its most salable attributes. Utility Distribution Companies (UDCs) can incentivize the location-specific siting of PVs by passing through transmission and distribution benefits to PV developers and end-users. Energy efficiency incentives can also accelerate the commercialization of PV technology. However, regulatory issues surrounding utility distribution company (UDC) ownership of distributed generation of any type may make ownership by the UDC problematic. This issue does not exist when an end user, PV developer, energy service company, community aggregator or direct access provider is incentivized to make the purchase.

Include Additional Funds In Energy Efficiency Budgets To Incentivize End User Purchase Of Distributed Renewables

As earlier stated, in an effort to identify as many means as possible of providing for the commercialization of emerging technologies, and in consideration of the fact that distributed renewables closely resemble energy efficiency and/or DSM measures, a logical means of encouraging end user purchase of those renewables that lend themselves to distributed generation applications, such as PVs, is to utilize new energy efficiency funds to incentivize private purchases. One way to accomplish this would be to buy down the price of distributed renewable generation to a point where the end user pays the same, or nearly the same price for both the required incremental power purchases and the renewable hardware costs together, as they would otherwise have paid for the electricity alone. This methodology could be implemented in addition to one of those previously identified, in that it would approach the end user market rather than the bulk power market, yet would yield benefits identical to the other commercialization avenues. This example is applicable to either residential or commercial applications of distributed renewables.

It should be stressed that the proposers do not advocate the expenditure of energy efficiency funds for this purpose at the expense of traditional energy efficiency programs, but rather recommend that, should this approach be chosen, monies from those appropriated for renewables as a whole be allocated for this purpose.

Administration

This approach could be administered through the same agency which is empowered to administer energy efficiency programs after restructuring. Again, market forces could be used to foster price competition in much the same way as the methods outlined earlier.

Require UDCs To Pass Through Local T&D Benefits To Accelerate The Commercialization Of Distributed Renewables On The Demand Side

As stated above, UDCs can play a decisive role in encouraging the implementation of location-specific distributed renewables in a way that does not conflict with vertical unbundling or any other facet of restructuring. This can be accomplished by UDCs passing through the localized benefits of PV in T&D systems to end users, third party PV developers, and retail providers, to the extent that these benefits exceed those of single net metering for residential customers. For example, the benefits of deferring a substation upgrade or feeder line upgrade, or of enhancing voltage support or reliability, can be quantified and offered as an incentive for end users or third parties to install PV. Location-specific real-time T&D pricing is another way to accomplish this.

Administration

By UDCs, with the oversight of the CPUC. By municipal utilities and others as ordered by law.

3. Implementation Questions

a. What is the Obligation?

a.1. How is "renewables generation" defined for purposes of qualifying for tradable "Renewable Energy Credits" under this proposed program? Do existing and incremental utility-owned renewable-resource generation qualify for Renewable Energy Credits?

All renewable technologies not currently cost competitive with non-renewables, but which hold potential for significant cost reductions given adequate markets would qualify. Utility owned generation would also qualify for Renewable Energy Credits (RECs).

a.2. What are renewable energy credits? How do they relate to energy portfolio management?

For an RPS-type mechanism, credits accrue when renewable electricity is generated. Using a modified RPS strategy, there would be three types of energy credits: RECs, Biomass Energy Credits (BECs) and Emerging Technology Credits (ETCs) for appropriate generators in the technologies assigned to each band of the portfolio. Each entity required to obtain credits must obtain them from technologies in each established band in accordance with renewable generation purchase requirements.

a.3. How are a diversity of renewables encouraged?

In the case of our proposed modifications to the RPS market-based approach, the proposers would add an emerging technologies band, similar to the biomass band of the RPS proposal. This band would provide a market in which emerging renewable technologies, which currently have higher costs than well established renewable technologies, could effectively compete. Photovoltaics and new solar thermal technologies cannot currently compete with wind or geothermal for the same class of RECs. The projected 1.5 to 2 cents per kWh that the RECs are expected to sell for will do very little to help provide markets for these new renewables, and there are no other state or federal programs on the horizon which could provide meaningful amounts of additional support to such emerging technologies. If the strategies proposed in this report are not adopted in order to provide for the needs of emerging technologies, it is difficult to envision other avenues for their continuing commercialization.

In the case of surcharge-type implementation approaches, the proposed modification creates a set- aside within the surcharge for emerging technologies to compete for production credits in order that all production credits are not awarded solely to a limited number of established technologies primarily in the wind, geothermal and solid-fuel biomass areas. The RD&D and Energy Efficiency program modifications could function in the same way as the surcharge credit award mechanism by basing credit awards on a variety of the desirable attributes of emerging renewable technologies.

This proposal suggests a number of paths which would provide real opportunities for new and less commercialized technologies to be able to effectively compete and obtain financial support, and would add meaningful amounts of a variety of solar resource technologies, as well as additional technologies in other resource areas, such as gas-fueled biomass.

a.4. Are currently-high-cost technologies or pre-commercial technologies fostered by this program?

Yes, see question a.3. above.

a.5. How is renewable self-generation handled? Is self-generated renewable energy eligible for Renewable Energy Credits, or for other means of support?

Surplus generation that is metered and sold at retail from grid-connected renewable facilities owned by customers or other third parties could be eligible for RECs. However, as with off-grid applications, self-generated power produced for on-site consumption would be administratively difficult to verify for the purpose of qualifying for RECs, which are currently designed to target centrally-generated renewable electricity that is sold into the grid at retail, However, self-generated on-grid applications could be supported through the public goods charge for energy efficiency programs because they help reduce customer demand on the California electric generating system. These specific applications could qualify for energy efficiency funds that are distinct from and in addition to those funds allocated to traditional energy efficiency and DSM programs to incentivize demand-side (self-generation) applications by the watt, or size of the system. These funds could be used to help buy down the up-front cost of purchasing a customer-owned generation system, as opposed to using RECs to incentivize customer-owned systems on a per kWh basis.

Third-party-owned, on grid generation connected on the customer side of the meter could qualify for RECs, provided the power is sold at retail. Power consumed on-site would, as above, be supported through energy efficiency programs.

a.6. How are hybrid fossil-fuel/renewable facilities handled?

Renewable generators using up to 25% fossil fuel would fully qualify as renewable. For generators using more than 25% fossil fuel, only the renewable-fueled fraction would qualify.

a.7. Does out-of-state generation qualify for Renewable Energy Credits? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

While restricting the program to in-state generation might be preferable, out-of-state generation could qualify assuming adequate restrictions could be placed on out-of-state hydro to avoid the problem of hydro capturing the RECs to the exclusion of other renewable technologies. California wind, geothermal and solar resources are large and should be able to compete with out-of-state plants of the same resource. Hydro would appear to be the only technology of concern.

a.8. If hydro is included, how are practical issues associated with hydropower handled?

Inclusion of hydro is possible but not necessary. Low cost hydro which can compete on a cost basis with non-renewables should not be included. Small hydro or more expensive, recently-licensed or environmentally-mitigated hydro, whose current costs are much higher than non-renewables, could be included if the amount of electricity and annual variations in output would not unduly disturb the workings of the implementation strategy.

a.9. How is utility-owned generation of distributed renewables handled? Is it eligible to receive RECs or surcharge funds? Does the proposal permit RECs or surcharge funds to accrue to distributed or other renewable applications that may involve the cross-subsidization of generation with T&D savings, or vice versa? Does the proposal permit or prohibit distributed or other utility-owned renewable power not sold through the power exchange to receive credits or surcharge funds?

Utilities are widely viewed as being a critical player in the effort to commercialize photovoltaic technology, and any restriction which prevents their involvement in this effort would be alarming. Nevertheless, distributed PV applications are in fact distributed generation, and in that sense should be subject to the same restrictions which may be placed on a utility's ability to own generation of any type. While the Commission may decide that the benefits of commercializing emerging technologies, such as PV, outweigh cross-subsidization or market power concerns, the Commission needs to address the market power, self-dealing, cross-subsidization, and functional unbundling issues associated with UDC ownership of distributed generation before such ownership is allowed. UDC ownership could also be inconsistent with the Commission's requirement that all utility and affiliate power be bought and sold through the power exchange. Until these issues are resolved, UDC- and utility Genco- and affiliate-owned distributed renewables should not qualify for RECs or public purpose surcharge monies.

a.10. What is the level for the requirement? How does this level relate to the level of renewables from 1990 to the present? Does the level of the requirement increase over time, and, if so, at what rate?

If modifying the Renewable Portfolio Standard proposal, the additional requirement of an emerging technology band could either increase the RPS requirement by 0.2% to 10.2% of generation or the 0.2% for emerging technologies could be incorporated within the 10% requirement, as with the proposed biomass band. In either case, the full 0.2% for emerging technologies would be phased in over the first four years of the program at the rate of 0.05% of generation per year. If modifying the EDF surcharge proposal, the overall level does not change, however a portion of the requirement would be set aside for emerging technologies. The RD&D and Energy Efficiency program models would result in the addition of the same amount of new resources as both the RPS and surcharge proposals.

a.11. Describe how, if at all, the compliance obligation adjusts during a transition period.

See answer to question a.10. above.

a.12 Does the proposal include a uniform requirement for all electric providers on a statewide basis?

Yes

a.13. What is the time-horizon for the program?

In order for new generation facilities to obtain the longest financing term and, therefore, the lowest annual costs, which in turn will result in the lowest renewable electricity costs to consumers, the chosen implementation strategy should have no specific time horizon or a minimum duration of at least 15 to 20 years. Portions of the program could sunset earlier if no longer needed.

a.14. Is the requirement established on a percentage of Megawatts or percentage of Megawatt-hours basis?

Either is possible, but using a MWh basis would avoid the problem of over-compensating under-producing facilities.

a.15. Does the proposal establish floors for certain technology types? What is the rationale for a technology floor, if proposed?

The proposal does not establish floors for certain technologies, but rather would establish a band or set aside for a range of emerging technologies to compete within. In the case of market-based strategies, no technology would have a guaranteed level of purchase or support, as with floors, but rather technologies in the emerging technology band would compete with each other. All selected emerging technologies could expect to remain in the emerging technology band for a limited time period. As their generation costs decline due to successful commercialization, technologies would move to other bands of an RPS-type mechanism with the ultimate goal to be complete removal from the program when their generation costs become competitive with non-renewable generation.

b. Where is the Obligation to Comply?

b.1. On whom is the requirement applied? Is the requirement applied only to entities under the Commission's jurisdiction, or is it applied statewide?

Optional, initially it could be applied either to only to those utilities under CPUC jurisdiction, however the proposers believe that ultimately any chosen renewables requirement should be applied to all California utilities.

b.2. Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences?

No difference.

b.3. What is the penalty for non-compliance? Should this penalty be interpreted as a cost-cap for the program?

No position on this question.

b.4. How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

No position on this question.

b.5. What provisions add flexibility to compliance, if any?

If there is a surplus of credits, credits could be saved or "banked" to be applied in the future years. If a shortage of credits caused credit prices in the spot market to reach the ceiling price, the program operator would become a "market maker" and sell credits at the ceiling price to satisfy the need.

b.6. How does the program ensure that the policy and its costs are non-bypassable, such as the CTC or the Public Goods surcharge?

By imposing the requirement to satisfy whatever renewables policy is implemented on all retail suppliers, for example, the costs would be non-bypassable to the maximum extent practicable.

c. How are Renewable Energy Credits Initially Allocated?

c.1. How are Renewable Energy Credits generated from existing renewable facilities (QFs and utility-owned) initially allocated? What impact does the initial allocation have on whether a vigorous market for Renewable Energy Credits, characterized by many buyers and sellers, forms?

No position on this question.

c.2. What is the relationship of the allocation of Renewable Energy Credits and the CTC or Public Goods Surcharge? Will Renewable Energy Credits accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid or otherwise avoid part or all of the CTC and Public Goods Surcharge?

Renewable Energy Credits would not accrue to off-grid renewables. However, grid-connected renewables would accrue credits on all generation output delivered to the grid. This should not encourage customers to disconnect from the grid, but just the opposite, if the credits have adequate value to a generator.
See also a.5. regarding renewable self-generation.

c.3. If customers or ratepayers are initially allocated Renewable Energy Credits, how are the credits administered?
No position on this question.

c.4. How would the proposed Renewable Energy Credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make them more or less cost-effective to ratepayers?

The modifications to implementation strategies proposed here deal primarily with new generation not currently under existing QF contracts and should, therefore, have little effect on the issue of buyouts.

c.5. How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

No position on this question.

c.6. Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

No position on this question.

d. How is the Program Administered?

d.1. What agency certifies Renewable Energy Credits?

No position on this issue.

d.2. What mechanisms are proposed for trading of Renewable Energy Credits? How do the trading mechanisms relate to the initial allocation of Renewable Energy Credits?

Renewable Energy Credits (RECs) or BECs or ETCs could be obtained by three methods: the party obligated to obtain credits (the "Obligatee") could generate renewable power from facilities it owns, the obligatee could enter into bilateral contracts with producers of credits for their purchase, or the obligatee could purchase credits on a multi-party, competitive "spot" market. Parties with excess credits of any band could sell or trade such credits through this spot market or directly with other parties through bilateral agreements.

d.3. What mechanisms are proposed for program oversight and mid-course corrections?

In the case of the RPS approach, the program administrator would periodically (1-3 years) review the current generation costs for technologies and adjust the value of any credit multipliers and possibly reconsider the continued inclusion of a particular technology in the emerging technology band. The administrator could also review and adjust any credit ceiling prices of the credits. For a surcharge approach, the administering agency could similarly periodically review what technologies should be included in any set aside for emerging technologies. Similarly, the administrator of the RD&D and/or Energy Efficiency Programs would conduct appropriate technology reviews.

d.4. What agency monitors and enforces compliance with the program, and how is it carried out?

No position on this issue.

e. Cost-Related Issues

e.1. What are the costs associated with the program, and who pays?

Assuming that the allocation of 0.2% of generation is added to the existing 10% specified in the RPS proposal**,** the program is estimated to cost only 10-15% more than the RPS proposal with the same parties bearing the costs as with the RPS proposal. With a surcharge approach, their need be no additional cost associated with the proposed modifications since the proposal only reallocates how surcharge monies are spent**.** If RD&D and Energy Efficiency Programs are funded through the surcharge approach, and the chosen method of implementing commercialization of emerging technologies is by adding a commercialization component to either of these programs, then the cost associated with the programs would be allocated from renewable surcharge funds to either RD&D or Energy Efficiency Programs for commercialization activities.

e.2. What cost-containment measures, if any, are provided?

For the RPS approach, a ceiling price on the cost of emerging technology credits in the spot market limits the maximum cost to comply. Additionally, competition between generation facilities and technologies within the emerging technology band, as well as the three different methods of acquiring credits outlined in question d.2. above, should maintain downward pressure on credit prices.

If commercialization is funded through a surcharge approach, cost-containment can be achieved by fixing the maximum surcharge monies available for the program.

e.3. If the program utilizes floors for certain technology types, what are the cost implications?

While the program does not utilize strict floors for certain technologies, it does create a band for emerging renewable technologies. While the credits for such emerging technologies (ETCs) are expected to cost more than the basic RECs or BECs of the RPS proposal, the much smaller size of this emerging technology band (0.2% of generation) results in little overall additional cost to the obligatees compared to the unmodified RPS proposal. The corresponding benefits of this emerging technology band, however, are great considering that promising technologies with the potential to reach low generation costs are afforded a pathway to enable them to achieve lower costs rapidly and efficiently, and, consequently, at a lower total cost that would otherwise have been the case.

e.4. Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

If the obligation is placed only on utilities under PUC jurisdiction, then cost shifting will occur since only the ratepayers of these utilities would be funding all renewables programs (assuming no other utilities implemented similar programs). If a uniform obligation on all utilities is imposed, cost-shifting issues will be avoided.

e.5. How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities?

The proposal provides for meaningful competition between technologies by permitting emerging technologies, and developers within such technologies, to compete within an emerging technologies band or set aside. Absent this, there is no meaningful competition if new, emerging technologies at higher early generation costs are forced to compete with mature, well-established technologies. Further, this proposal makes it possible for existing and newly constructed facilities employing emerging renewable technologies to compete with each other, while likewise permitting competition between existing and new facilities using well-established technologies.

e.6. What implications, if any, does the proposal have in defining the roles of the LDC and of competitive suppliers of electricity?

Unknown.

e.7. What is the consistency of this proposal in relation to cost-related guidance provided by the PUC Roadmap?

Unknown.

f. How does the Program Fit with Other Aspects of Electric Industry Reform?

f.1. Is the program compatible with the existence of an Independent System Operator? A Power Exchange? A Direct Access Market? Is the proposal consistent with the Commission's vision of the role of the Power Exchange and ISO?

No position on this question.

f.*2. Is the proposal dependent in any way on the Power Exchange or ISO? If so, are any additional protocols necessary?*

No position on this question.

f.3. Does the proposal involve conflicts of interest between distribution and competitive retail service? If so, how are they resolved?

No position on this question.

f.4. How does the program avoid conflicts of jurisdiction between state and federal levels?

No position on this question.

f.5. What is the relationship between the proposal and Direct Access "Green Marketing"?

Direct Access "Green Marketing" might benefit some renewable technologies, but not others, as the renewable technologies and the relative proportions of each to be "Green Marketed" is unknown and uncontrollable. The proposed program would benefit all technologies, with appropriate levels of benefit in relationship to the different technologies' levels of commercialization.

f.6. What is the relationship between the proposal and Performance Based Ratemaking (PBR)? Does the proposal place Renewable Energy Credits under PBR, or exclude Renewable Energy Credits from PBR?

No position on this question.

f.7. Does the program create any potential market power problems involving the generation market or Renewable Energy Credits?

No position on this question.

f.8. How does the proposal relate to any consumer protection or consumer education efforts? For example, *a. Rules for new entrants: Does the proposal entail any licensing requirements for new entrants? Should compliance with the minimum renewables requirement be a condition of selling power at the retail level?*

b. Consumer education: Does the proposal require any consumer education? For example, how does the proposal protect consumers from "green marketing" programs where marketers collect twice -- once for credit sales and once for "green" power sales, thereby not increasing total green power? This could entail, e.g., disclosure requirements to inform consumers about the amount of renewable energy they are purchasing that are supported by Renewable Energy Credits, or statements regarding price stability or price risks associated with the seller's resource portfolio. Would RECs accrue to utilities from green pricing programs where utilities have unique customer information and access?

No position on this question.

f.9. How, if at all, does the proposal relate to RD&D programs funded by the Public Goods Charge?

Should the Commission decide that the appropriate vehicle for commercializing emerging technologies is to add a commercialization component to RD&D programs, then the proposal outlines a means for accomplishing this. It describes a way for technologies emerging from RD&D to construct commercial-scale plants and to receive the necessary prices for the electricity from these early, more expensive plants to permit the industry to make the investment necessary to reduce generation costs to lower levels consistent with a mature technology.

f.10. How, if at all, does the proposal relate to energy efficiency programs funded by the Public Good Charge?

Should the Commission decide that one appropriate vehicle for commercializing emerging technologies is to utilize new energy efficiency funds to buy down the costs of customer-owned distributed renewables, then the proposal outlines a means for accomplishing this. It conceptualizes a method for bringing the price of electricity generated from distributed renewables situated on the customer side of the meter to market levels by using the funds to reduce first costs of systems, allowing the owner to operate the system at a cost near or at that which they would have paid to purchase electricity had no system been installed. This proposal is premised on the assumption that energy efficiency programs would be restored to their historic funding levels, and that funds for distributed renewables would be separate and distinct from, and in addition to, funds for these “traditional” energy efficiency programs.

f.11. How does this proposal affect the CEQA compliance work recently initiated by the Commission?

No position on this question.

g. Legislative Requirements

g.1. Can the Commission implement this proposal by itself, or is legislation needed? What is the status of entities not under the Commission's jurisdiction in this program?

Can be implemented for regulated utilities alone by CPUC, although the inclusion of all utilities by Legislative action would be preferable.

g.2. What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the CPUC's 1998 implementation goal?

No position on this question.

4. Positions of the Parties in Favor/Neutral/Oppose

Comments of the CPUC’s Division of Ratepayer Advocates, the Utility Consumers Action Network, and the Independent Power Providers

DRA/UCAN/IPP conditionally support this proposal because:

1. UDCs and affiliates do not receive credits or surcharge moneys to own distributed renewables on customer or other sites. [CalSEIA has flagged the question of UDC ownership for resolution by the Commission.]

2. UDCs pass through local T&D benefits to accelerate commercialization of distributed renewables owned by customers and competing providers.

DRA/UCAN/IPP's condition for supporting this proposal is:

3. It does not raise rates.

4. Distributed renewables at customer locations are supported as energy efficiency measures connected on the demand side of the meter, rather than through the renewables program.

5. Central station emerging renewables are funded through a surcharge, rather than a band.

Comments of AWEA/CBEA/GEA/STEA

SUPPORT WITH MODIFICATION: As stated in our proposal, we support policies and funding to support the commercialization of emerging renewable technologies. Commercialization would be best achieved through a surcharge, but we do not support the "auctioned credit" approach for the practical reasons stated in appendix. Commercialization programs should be handled by the RD&D administrator, allowing flexibility and judgment in allocation of funds. Accomplishing commercialization by adding a tiny technology band to the market-wide RPS program and adding administrative involvement is inconsistent with the RPS approach which is geared toward bulk-power resources and intended to minimize administrative involvement.

Comments of Some Surcharge/Production Credit Proposers

(Note: Where Surcharge/Production Credit Proposal supporters' names appear independently in these "Position of Parties" subsections, their position is not included in the following position statement made on behalf of the remaining supporters.)

Neutral:

1. Recognizes emerging technologies: Offers emerging, environmentally sensitive technologies a vehicle to achieve commercial viability which otherwise may be difficult to obtain.

2. ***Aims for a small market at high cost: This proposal would claim for emerging technologies approximately half of the total suggested annual auction award funds collected under the Surcharge/Production Credit proposal. Possibly special legislation would be a better vehicle to provide the level of funding the technologies in this niche demand.***

3. ***Increases administrative burden: Requirements for an additional type of energy credits and the requisite purchase/sale/compliance oversight increases administrative burdens of an MRPR-based proposal.***

Comments of Orange County, Sonoma County, the City of Sacramento, NEO Corporation

We oppose this proposal because it discriminates among technologies with tiers and is not market driven. All renewables should be competitive in their own market. Funds should be distributed through a simple price only auction. Regulated or engineered tiers are an invitation to manipulate engineering, construction and operating and maintenance costs. It is a BRPU approach we strongly oppose. Perhaps his proposal would be a way to handle RD&D funding.

Comments of the Union of Concerned Scientists

Support
Good Points: Addresses commercialization of new technologies, which otherwise may languish between RD&D and support offered by RPS. UCS supports three approaches: adding commercialization component to RD&D programs, adding energy efficiency funds for distributed renewables, and passing through local T&D benefits. Supplementing RPS with PGC funding for commercialization on top of T&D incentives minimizes complexity, while maintaining market-based approach of RPS. RD&D administrator can apply flexibility and judgment in allocation of funds. Additional energy efficiency funds to incentivize end user purchase overcomes high capital cost barrier.
Bad Points: Assignment of credit multipliers for Emerging Technology Credits band administratively complex, open to influence by stakeholders.

Comments Los Angeles Department of Water and Power (LADWP)

Procurement of renewable resources should be the responsibility of some state entity for the state power pool and the above-market cost of compliance should be borne uniformly by all customers served by the UDC on a non-bypassable basis. Rather than having many entities responsible for procurement of renewables, having one entity responsible for the state's procurement of renewables will minimize the compliance transaction costs. The level and diversity of renewable resource mix should be established by the legislature which would determine the appropriateness of establishing set asides for certain renewable resources. The renewables program should be reviewed every five years.

Comments of Southern California Edison

The CalSEIA, et al. proposal is based on the argument that emerging technologies need more financial assistance to be competitive than other, more established, renewables. This proposal proposes modifications to both the surcharge and MRPR proposals to provide more assistance to emerging technologies.

If development of emerging technologies is a Commission objective, the simplest way to provide added support for these technologies is through the surcharge approach. A percentage of the surcharge funds could be reserved for promising emerging technologies and distributed either through a separate program or through a set-aside as part of the competitive auction.

Comments of the California Integrated Waste Management Board

Support with conditions: The CEC's proposal expands the Renewable Portfolio Standard to include a band for a limited number of projects which use "emerging" technologies. The eligible technologies would be determined at a later date.

The proposed emerging technology band could provide nearly as much renewable energy development as the production credit model while providing funding for higher cost technologies.

The emerging technology band borders on a Research Development and Demonstration proposal, but could be added to other RPS proposals with some minor modifications.

Comments of Don Augenstein

I strongly endorse the "Emerging Renewables Technology Commercialization Pathway" proposal of CalSEIA, et al. The problem of advancement of technologies in early stages of commercialization is serious and this proposal addresses that particular problem. Its mechanism of allowing added RECs for projects with environmental benefits is also endorsed.

Comments of SoCAL Gas

OPPOSE - Proposal calls for an emerging technology subsidy. Its goal is to enable currently under-represented renewable technologies to become active participants in the mix of available renewable technologies. The concept is based on the idea that a minimum level of production is needed for production efficiencies and cost reductions. It calls for the CEC to bridge the gap between RD&D and commercialization. However, this proposal is nothing more than an industrials policy, relying on an infant industry argument, where the CEC believes it can pick winners and losers better than the marketplace. There is no economic justificstion for such a policy.

Comments of CalSEIA, et al. on their Own Proposal

The proposers believe that by formulating a means for commercializing solar and other emerging technologies within the electric industry restructuring proceedings, the Commission and/or the legislature will be establishing a pathway for the commercialization function which existed in years past, but does not exist today, and without which many of today's commercialized renewable technologies would not enjoy their current low generation costs.

Comments of SDG&E

Oppose:

- No cost limitation.
- Under MRPR this proposal would inequitably burden consumers. San Diego area consumers would see rate increases.
- Requires significant funding expenditures without any guarantee that projects would benefit California consumers.
- Distinction between emerging technologies and RD&D related projects/project funding unclear.
- Funding possibly available from other sources (e.g RD&D, tax incentives, etc.).
- Could be inconsistent with State policy. State/CPUC must decide what types of emerging technologies to promote.

Comments of IEP

- Does not address existing renewables
- In the absence of full direct access, does not provide adequate price signals to sustain competition for the production credits. For example, in the absence of any direct access, the sole purchaser is the utility under a SOl contact, and the price paid to all renewable producers will be the marginal clearing price of the PX. The only variable affecting allocation bids will be the producer's operating costs, which remain relatively fixed over time. The absence of buyer/seller price variability will likely result in a single entity garnering all the production credits.

Comments of PG&E

PG&E believes that the heart of both the RPS and surcharge proposal is to have renewable-on-renewable competition and maximize the generation of renewable energy. Should society wish to explicitly support the development of higher-cost renewables as a way to encourage their eventual commercialization, this could be done as either a second auction within the surcharge or an explicit development fund within public good R&D.

Care should be taken to keep it simple.

Appendix A

PRELIMINARY STATE-WIDE AND AGGREGATED-IOU ELECTRIC POWER DATA

Tables A.1 and A.2 present disaggregated data on California renewables generation and California renewables supply for the 1990 to 1994 period. Data for 1995 are not yet available. Utility-owned renewables, renewable QF-sales, renewable self-generation, and renewables imports are all estimated, and renewable resource-specific data are provided. In addition, data on total generation, retail sales, and retail revenues are also listed. These data are presented both to respond to the CPUC's directions, and so that each of the proposals contained in this report may use a consistent set of data to define their proposals.

The first table presents state-wide data. The second table presents the same categories of information, but covers only the aggregate data for the IOU's serving California. Appendix B, which is supplied by the California Energy Commission, presents utility-specific renewables data for the three largest IOUs serving the state (SCE, SDG&E and PG&E).

The data in this Appendix and in Appendix B are preliminary, have not been openly and completely reviewed, and should not be used to determine the final renewable program, or its scope. The development of this data was a significant but challenging task to complete within the working group structure. We have managed to develop and release this preliminary data by acknowledging, as a group, that it needs to be labeled as such. Many advocates have economic or other interests that are affected by program targets. If the CPUC intends to rely upon this data in developing a renewables program, the Working Group recommends that the data be examined in an evidentiary hearing.

The renewables data contained in this Appendix were produced by a joint effort of the California Energy Commission and the three largest IOUs (SCE, SDG&E, and PG&E). Each of these IOUs submitted confidential[32] data to the CEC on utility generation, QF purchases, and imports. CEC staff provided similar data from the CEC's database (whose sources include FERC forms, the CEC's Quarterly Fuels and Energy Report data-base, and the IOUs' quarterly small power production reports to the CPUC), in addition to estimates for self-generation (checked against IOU estimates, when available). Given the amount of estimation involved in the compilation of the available data for this purpose, the data contained in these tables should be considered estimates rather than a precise compilation of measured actual

[32] Confidentiality constraints to protect independent producers selling energy to the IOUs require that the data for the three large IOUs not be reported by individual utility. Therefore, all utility-specific data supplied by the IOUs to the CEC is confidential. The CEC used this confidential data to create the aggregate IOU data provided in the second table.

generation. The IOU-specific data supplied in Appendix B come solely from public CEC sources, and therefore differ from those provided in this section. Specifically, the data contained in Appendix B were not validated by the IOUs.

Renewables generation is disaggregated by resource type, including hydroelectric, geothermal, wind, biomass, and solar. Where appropriate, distinctions are made between in-state renewable energy facilities and out-of-state facilities serving California load. The solar thermal generation data apply a 25% derating factor to the total output of the solar thermal power-plants to account for natural-gas back-up. An estimate for the amount of Pacific Northwest hydro imported into the state is obtained by assuming 80% of the total economy energy imports from this region come from hydroelectric facilities.

TABLE A-1
RENEWABLE GENERATION FOR CALIFORNIA USE
ENERGY IN GIGAWATTHOURS/YEAR (MILLION KILOWATTHOURS/YEAR)
STATEWIDE

GENERATION TYPE	1990	1991	1992	1993	1994
Total Renewable Generation	78,270	73,868	66,318	82,093	66,299
Utility-Owned Resources	35,305	31,810	31,274	48,878	33,032
Hydroelectric	25,612	22,728	22,033	40,440	25,024
In-state	25,469	22,488	21,834	40,255	24,777
Out-of-state	143	240	199	185	247
Other Renewables	9,693	9,082	9,241	8,438	8,008
Geothermal	9,691	9,079	9,240	8,435	8,007
Wind	0	0	0	0	0
Biomass	0	0	0	0	0
Solid-fueled	0	0	0	0	0
Biogas	0	0	0	0	0
MSW	0	0	0	0	0
Solar	2	3	1	3	1
Thermal	0	0	0	0	0
PV	2	3	1	3	1
QF Sales	14,749	16,119	16,474	17,960	18,130
Hydroelectric	619	579	544	1,182	633
In-state	619	579	544	1,182	633
Out-of-state	0	0	0	0	0
Other Renewables	14,130	15,540	15,930	16,778	17,497
Geothermal	6,353	6,891	7,050	7,435	7,691
Nevada	0	0	0	0	0
Other	6,353	6,891	7,050	7,435	7,691
Wind	2,464	2,747	2,707	2,881	3,281
Biomass	4,802	5,347	5,648	5,821	5,927
Solid-fueled	4,458	4,986	5,263	5,414	5,516
Biogas	211	227	250	270	271
MSW	133	134	135	137	140
Solar	511	555	525	641	598
Thermal	504	550	521	639	598
PV	7	5	4	2	0
Self-Generation	957	958	958	959	959
Biomass	957	958	958	959	959
Solid-fueled	583	583	583	583	583
Biogas	346	347	347	348	348
MSW	28	28	28	28	28
Renewable Imports					
PNW Hydro (80% of total)	25,332	23,055	15,680	12,373	12,252
Mexico Geothermal	1,927	1,926	1,932	1,923	1,927
Total Non-Renewable Generation	174,085	168,475	179,217	159,934	191,500
TOTAL GENERATION	**252,355**	**242,343**	**245,535**	**242,026**	**257,799**
Total Non-Hydro Renewables	26,707	27,506	28,061	28,098	28,391
RETAIL SALES (GWh)	211,062	208,679	213,386	210,467	213,704
RETAIL REVENUES (MM$$)	18,381	19,660	20,611	20,301	20,461

Renewables Working Group, Draft (July 1, 1996)

TABLE A-2

RENEWABLE GENERATION FOR CALIFORNIA USE
ENERGY IN GIGAWATTHOURS/YEAR (MILLION KILOWATTHOURS/YEAR)
INVESTOR-OWNED UTILITIES

GENERATION TYPE	1990	1991	1992	1993	1994
Total Renewable Generation	47,465	48,378	40,828	52,155	41,319
Utility-Owned Resources	17,885	18,254	17,567	27,026	17,366
Hydroelectric	10,561	11,307	10,560	20,535	11,342
In-state	10,418	11,067	10,361	20,350	11,095
Out-of-stat	143	240	199	185	247
Other Renewables	7,324	6,947	7,007	6,491	6,024
Geothermal	7,324	6,947	7,007	6,491	6,024
Wind	0	0	0	0	0
Biomass	0	0	0	0	0
Solid-fuele	0	0	0	0	0
Biogas	0	0	0	0	0
MSW	0	0	0	0	0
Solar	0	0	0	0	0
Thermal	0	0	0	0	0
PV	0	0	0	0	0
QF Sales	14,727	16,097	16,452	17,938	18,108
Hydroelectric	597	557	522	1,160	611
In-state	597	557	522	1,160	611
Out-of-stat	0	0	0	0	0
Other Renewables	14,130	15,540	15,930	16,778	17,497
Geothermal	6,353	6,891	7,050	7,435	7,691
Nevada	0	0	0	0	0
Other	6,353	6,891	7,050	7,435	7,691
Wind	2,464	2,747	2,707	2,881	3,281
Biomass	4,802	5,347	5,648	5,821	5,927
Solid-fuele	4,458	4,986	5,263	5,414	5,516
Biogas	211	227	250	270	271
MSW	133	134	135	137	140
Solar	511	555	525	641	598
Thermal	504	550	521	639	598
PV	7	5	4	2	0
Self-Generation	919	920	920	921	921
Biomass	919	920	920	921	921
Solid-fuele	583	583	583	583	583
Biogas	308	309	309	310	310
MSW	28	28	28	28	28
Renewable Imports					
PNW Hydro (80% of total)	12,007	11,181	3,956	4,347	2,997
Mexico Geothermal	1,927	1,926	1,932	1,923	1,927
Total Non-Renewable Generation	140,991	138,179	153,538	143,506	157,412
TOTAL GENERATION	**188,456**	**186,557**	**194,366**	**195,661**	**198,731**
Total Non-Hydro Renewables	24,300	25,333	25,789	26,113	26,369
RETAIL SALES (GWh)	154,961	153,855	157,833	155,661	158,573
RETAIL REVENUES (MM$$)	14,532	15,558	16,279	16,034	16,486

Renewables Working Group, Draft (July 1, 1996)

Appendix B

PRELIMINARY IOU-SPECIFIC RENEWABLES DATA

The following data table reports on categories of information similar to that found in Appendix A, but lists utility-specific renewables data for the three largest IOUs serving the state (SCE, SDG&E, and PG&E). This data comes solely from public California Energy Commission (CEC) sources, and therefore differs from that provided in Appendix A. Specifically, the data contained in this Appendix was not validated by the IOUs.

The data in this Appendix, as in Appendix A, are preliminary, have not been openly and completely reviewed, and should not be used to determine the final renewable program, or its scope. The development of this data was a significant but challenging task to complete within the working group structure. We have managed to develop and release this preliminary data by acknowledging, as a group, that it needs to be labeled as such. Many advocates have economic or other interests that are affected by program targets. If the CPUC intends to rely upon this data in developing a renewables program, the Working Group recommends that the data be examined in an evidentiary hearing.

CEC data on renewables generation is disaggregated by resource types that are slightly different from those presented in Appendix A of the report. Where appropriate, distinctions are made between in-state renewable energy facilities and out-of-state facilities service California load. The solar thermal generation data applies a 25% de-rating factor to the total output of the solar thermal power plants to account for natural gas back-up. An estimate for the amount of Pacific Northwest hydro imported into the state is obtained by assuming 80% of the total economy energy imports comes from hydroelectric facilities.

Data sources for the renewables generation listed in the table include FERC forms, the CEC's Quarterly Fuels and Energy Report database, the IOUs' quarterly small power production reports to the CPUC, and in-house CEC staff estimates of self-generation. Because none of these data sources is comprehensive and some of them are often incomplete, data gaps do occur. Not all utilities report data and some report it intermittently or imperfectly. The data gaps are filled with CEC staff estimates of what generation might have been, based on assumed performance factors (dependable capacity, annual capacity factor, etc.).

The CEC annually compiles data from a variety of sources to estimate a quantity it defines as "Total Generation for California Use," which is included in the following data table. This category represents the quantity of electricity that is "consumed" by the following California "uses": energy user energy requirements (including end-use by self-generators), transmission and distribution losses, and net bulk power exports out of California. A statewide total of this compilation of data is published annually by the Department of Finance in the California Statistical Abstract. CEC staff has not typically reported the compiled data in a disaggregated way (for each of the state's more than forty individual utilities). The public data sources which are compiled by the CEC staff are utility-specific, however.

TABLE B-1
Renewables Portion of 1994 Total Generation for California Use *
Annual Energy in Gigawatthours/year (million kilowatthours/year)

		Edison	SDG&E	PG&E	Other	Total
Total Generation for California Use		**89,138**	**18,837**	**81,367**	**68,269**	**257,611**
Total Renewables for California Use (Includes all hydro)		16,644	2,226	23,630	24,799	67,299
Non-hydro Renewables for California Use (Excludes all hydro)		**11,810**	**1,374**	**13,502**	**1,886**	**28,572**
Nonutility Renewables	**All kinds**	**11,389**	**64**	**7,855**	**65**	**19,373**
	Hydro	192	13	378	22	605
	Small	192	13	307	22	534
	Other QF	0	0	71	0	71
	Geothermal	6,432	0	1,299	0	7,731
	Nevada	557	0	0	0	557
	Other CA	5,875	0	1,299	0	7,174
	Organic Waste	2,164	51	4,918	38	7,171
	LNF/Digest	947	51	195	38	1,231
	Solid Wast	950	0	4,424	0	5,374
	MSW					
	Self-Ger	0	0	0	0	0
	Sales	267	0	299	0	566
	Wind	2,003	0	1,260	5	3,268
	Solar 1/	598	0	0	0	598
Imported PNW Hydroelectricity		**1,338**	**839**	**1,958**	**8,963**	**13,098**
(Total PNW Imports)		1,673	1,049	2,447	11,204	16,373
Utility-Owned Renewables	**All kinds**	**3,917**	**1,323**	**13,817**	**15,771**	**34,828**
	Hydro	3,304	0	7,792	13,928	25,024
	Geoth	613	1,323	6,024	1,817	9,777
	CFE	613	1,323	0	0	1,936
	IOUs	0	0	6,024	0	6,024
	Other Utility	0	0	0	1,817	1,817
	Organic waste	0	0	0	0	0
	Wind	0	0	1	25	26
	Solar	0	0	0	1	1

*** California use includes requirements for end use (including self-generation), line losses, and wholesale exports.**

1/ Reported solar thermal data, 797 GWh, was reduced 25% to adjust for assumed natural gas burn.

Energy Forecasting & Resource Assessment Division Staff, California Energy Commission, July 1, 1996

Appendix C

IMPLEMENTATION QUESTIONS

The Commission has specifically identified a number of implementation issues and requested the Renewables Working Group to report back with recommendations on these issues. In addition, the Working Group has identified additional implementation issues that need to be addressed as part of the Commission's minimum renewables purchase requirement policy, as well as a set of linkages to other areas of restructuring that require attention. These issues are identified generically in the following subsections. In Chapter 4 of this report, which contains the full text of the proposals, the questions are answered for each of the specific implementation strategies that are proposed by members of the Working Group. Where appropriate, rationales for the answers are also be provided.

a. What is the Obligation?

a.1. How is "renewables generation" defined for purposes of qualifying for tradable "Renewable Energy Credits" under this proposed program? Do existing and incremental utility-owned renewable-resource generation qualify for Renewable Energy Credits?

a.2. What are renewable energy credits? How do they relate to energy portfolio management?

a.3. How is a diversity of renewables encouraged?

a.4. Are currently-high-cost technologies or pre-commercial technologies fostered by this program?

a.5. How is renewable self-generation handled? Is self-generated renewable energy eligible for Renewable Energy Credits, or for other means of support?

Note: Other possibilities to support self-generation of renewables include energy-efficiency or RD&D program funding from the Public Goods Charge, or requiring utilities to pass through localized or systemic T&D savings to customers and third parties who install distributed renewables systems.

a.6. How are hybrid fossil-fuel/renewable facilities handled?

a.7. Does out-of-state generation qualify for Renewable Energy Credits? Is it desirable or necessary to protect in-state California renewable energy generators from out-of-state competition? Is it possible?

a.8. If hydro is included, how are practical issues associated with hydropower handled?

Note: These issues include but are not limited to: responding to large year-to-year fluctuations in output; defining "environmentally mitigated" hydro; guarding against Northwest hydro capturing the renewables market created by the requirement; and avoiding cross-subsidizing other uses of hydro facilities, such as irrigation, flood control, recreation, etc.

a.9. How is utility-owned generation of distributed renewables handled? Is it eligible to receive RECs or surcharge funds? Does the proposal permit RECs or surcharge funds to accrue to distributed or other renewable applications that may involve the cross-subsidization of generation with T&D savings, or vice-versa? Does the proposal permit or prohibit distributed or other utility-owned renewable power not sold through the power exchange to receive credits or surcharge funds?

Note: The CPUC ruled that during the five-year transition to direct access, UDCs must sell all of their electric generation (presumably central or distributed) through the Exchange, and must serve their customers with power purchased solely through the Exchange. Taking power outside of the Exchange is prohibited. Some applications of distributed renewables may not, however, lend themselves to sale through the Exchange.

a.10. Are existing and incremental utility-owned renewables included?

a.11. What is the level for the requirement? How does this level relate to the level of renewables from 1990 to the present? Does the level of the requirement increase over time, and, if so, at what rate?

a.12. Describe how, if at all, the compliance obligation adjusts during a transition period?

a.13. Does the proposal include a uniform requirement for all electricity providers on a state-wide basis?

a.14. What is the time-horizon for the program?

Note: Financing of new renewables facilities, which increases competition, may be contingent on an expectation that a market for renewable power will exist for an extended period of time.

a.15. Is the requirement established on a percentage of Megawatts or percentage of Megawatt-hours basis?

a.16. Does the proposal establish floors for certain technology types? What is the rationale for a technology floor, if proposed?

b. Where is the Obligation to Comply?

b.1. On whom is the requirement applied? . Is the requirement applied only to entities under the Commission's jurisdiction, or is it applied statewide?

Note: The Commission suggested either retail providers of electricity or generators

b.2. Are regulated retail providers treated similarly to unregulated retail providers? If not, what are the differences?

b.3. What is the penalty for non-compliance? Should this penalty be interpreted as a cost-cap for the program?

b.4. How is non-compliance determined? Who is responsible for determining non-compliance and for resolving disputes arising from such a determination?

b.5. What provisions add flexibility to compliance, if any?

b.6. How does the program ensure that the policy and its costs are nonbypassable, such as the CTC or the Public Goods surcharge?

c. How are Renewable Energy Credits Initially Allocated?

c.1. How are Renewable Energy Credits generated from existing renewable facilities (QFs and utility-owned) initially allocated? What impact does the initial allocation have on whether a vigorous market for Renewable Energy Credits, characterized by many buyers and sellers, forms?

c.2. What is the relationship between the allocation of Renewable Energy Credits and the CTC or Public Goods Surcharge? Will Renewable Energy Credits accrue to technologies, such as on- and off-grid renewables, in a way that would encourage customers to disconnect from the grid or otherwise avoid part or all of the CTC and Public Goods Surcharge?

c.3. If customers or ratepayers are initially allocated Renewable Energy Credits, how are the credits administered?

c.4. How would the proposed Renewable Energy Credit allocation affect negotiations to buy out existing QF contracts? Would it encourage or discourage such buyouts? Would it make them more or less cost-effective to ratepayers?

c.5. How does the initial allocation deal with the possibility of windfall profits accruing to individual renewables generators, or types of generators?

c.6. Does the proposal potentially increase the value of utility-owned renewable resources in a way that would encourage their divestiture? If so, how should ratepayer interests be addressed?

d. How is the Program Administered?

d.1. What agency certifies Renewable Energy Credits?

d.2. What mechanisms are proposed for trading of Renewable Energy Credits? How do the trading mechanisms relate to the initial allocation of Renewable Energy Credits?

d.3. What mechanisms are proposed for program oversight and midcourse corrections?

d.4. What agency monitors and enforces compliance with the program, and how is it carried out?

e. Cost-Related Issues

e.1. What are the costs associated with the program, and who pays?

Note: Cost reduction can occur in three ways: First, to the extent that programs encourage competition among renewable generators, the price of renewable power should decline. Second, to the extent that proposals build confidence in the long-term viability of the renewable power industry, financing costs could decline, and competition increase, lowering the cost of renewable generation. Third, costs associated with program structure and operation may differ from one proposal to the next.

e.2. What cost-containment measures, if any, are provided?

e.3. If the program utilizes floors for certain technology-types, what are the cost implications?

e.4. Will implementation of the program lead to cost-shifting between consumer groups or regions of the state?

e.5. How is competition within and between renewable technologies encouraged? Between existing renewables facilities and potential new facilities?

e.6. What implications, if any does the proposal have in defining the roles of the LDC and of competitive suppliers of electricity?

e.7. What is the consistency of this proposal in relation to cost-related guidance provided by the PUC Roadmap?

f. How does the Program Fit with Other Aspects of Electric Industry Reform?

f.1. Is the Program compatible with the existence of an Independent System Operator? A Power Exchange? A Direct Access Market? Is the Proposal consistent with the Commission's vision of the role of the Power Exchange and ISO?

f.2. Is the Program dependent in any way on the Power Exchange or ISO? If so, are any additional protocols necessary?

f.3. Does the proposal involve conflicts of interest between distribution and competitive retail service? If so, how are they resolved?

f.4. How does the program avoid conflicts of jurisdiction between state and federal levels?

f.5. What is the relationship between the Proposal and Direct Access "Green Marketing"?

f.6. What is the relationship between the proposal and Performance Based Ratemaking (PBR)? Does the proposal place Renewable Energy Credits under PBR, or exclude Renewable Energy Credits from PBR?

f.7. Does the Program create any potential for market-power problems involving the generation market or Renewable Energy Credits?

Note: Generation-market power includes system-level and locational market-power.

f.8. Does the proposal relate to any consumer protection or consumer education efforts? For example:

(a) Rules for New Entrants. Does the proposal entail any licensing requirements for new entrants? Should compliance with the minimum renewables requirement be a condition of selling power at the retail level?

(b) Consumer Education. Does the Proposal require any consumer education? For example, how does the proposal protect consumers from "green marketing" programs in which marketers collect twice--once for credit sales and once for "green" power sales, thereby not increasing total green power? This could entail, e.g., disclosure requirements to inform consumers about the amount of renewable energy they are purchasing that is supported by Renewable Energy Credits, or statements regarding price stability or price risks associated with the seller's resource portfolio. Would RECs accrue to utilities from green-pricing programs where utilities have unique customer information and access?

f.9. How, if at all, does the Proposal relate to RD&D programs funded by the Public Goods Surcharge?

f.10. How, if at all, does the Proposal relate to energy-efficiency programs funded by the Public Goods Surcharge?

f.11. How does this Proposal affect CEQA compliance work recently initiated by the Commission?

g. Legislative Requirements

g.1. Can the Commission implement this proposal by itself, or is legislation needed? What is the status of entities not under the Commission's jurisdiction in this program?

g.2. What steps are needed to implement the program, and how long would it take? How does this implementation timing relate to the Commission's 1998 implementation goal?

Appendix D

ACRONYMS

BEC - Biomass Energy Credit, a subset of Renewable Energy Credits.
BRPU - Biennial Resource Plan Update
Btu - British thermal unit
CARB - California Air Resources Board
CCAP - Climate Change Action Plan
CEC - California Energy Commission
CEQA - California Environmental Quality Act
CH4 - methane
CO - Carbon monoxide
CO2 - Carbon dioxide
CPUC - California Public Utilities Commission
CTC - Competition Transition Charge
DGS - California Department of General Services
DOE - Unites States Department of Energy
DSM - Demand-side management
DWR - California Department of Water Resources
EEI - Edison Electric Institute
EPA - Environmental Protection Agency (same as USEPA)
EPAct - Energy Policy Act of 1992
EPRI - Electric Power Research Institute
ETC - Emerging technology credits
ER-94 - California Energy Commission's *1994 Electricity Report*
FERC - Federal Energy Regulatory Commission
GEC - Greenhouse Environmental Credit
Gwh - gigawatthour
IOU - Investor owned utility
IPCC - Intergovernmental Panel on Climate Change
ISO - Independent System Operator
ISO4 - Interim Standard Offer 4 Power Purchase Agreement
kW - kilowatt
kWh - kilowatthour
LDC - Local distribution company (same as UDC)
LFG - landfill gas
MRPR - Minimum Renewables Purchase Requirement
MW - megawatt
Mwe - megawatts of energy

NA - not applicable
NOx - nitrogen oxide
PBR - performance based ratemaking or regulation
PPA - power purchase agreement
PUC - same as CPUC
PURPA - Public Utilities Regulatory Policies Act
PV - photovoltaic
PX - power exchange (same as WEPEX)
QCF - qualifying capacity factor
QF - qualifying facility
REC - Renewable Energy Credit - tradable certificates of proof that one kWh of electricity has been generated by the appropriate renewable-fueled source and sold to an end-user in California.
RECLAIM - Regional Clean Air Incentives Market, an emission reduction credit trading program sponsored by the South Coast Air Quality Management District.
RD&D - research, development and demonstration
RDD&C - research, development, demonstration, and commercialization
RPS - Renewables Portfolio Standard
RRCC - Renewable Resource Capacity Credits
RREGT - resource electric generation technologies
RWG - Renewables Working Group
SBRPS - Single Band Renewable Portfolio Standard
SO4 - Standard Offer 4 Power Purchase Agreement
SOx - sulfur dioxide
SRAC - short-run avoided cost
T&D - transmission and distribution
UDC - utility distribution company (same as LDC)
USEPA - United States Environmental Protection Agency
VOC - volatile organic compound
WEPEX - Western Power Exchange

Appendix E

LIST OF PARTICIPATING ORGANIZATIONS

A. PARTICIPATING ORGANIZATIONS SUBMITTING/SUPPORTING PROPOSALS

AWEA - The American Wind Energy Association has represented all facets of the U.S. wind energy industry since 1974. AWEA's 750 members, including 155 members in California, includes 7 turbine manufacturers, 10 project developer/operators, 12 accessory parts manufacturers, 22 consultants, academicians and interested individuals.

CalSEIA - California Solar Energy Industries Association

Cambrian Energy Development LLC

CBEA - The California Biomass Energy Alliance has 19 member companies, operating 34 plants in California, representing over 90 percent of the operable solid fuel biomass plants in the state.

City of Sacramento

City of San Diego Metropolitan Wastewater Department (MWWD) - treats the wastewater generated by a greater San Diego population of 1.8 million from 15 cities and districts contributing approximately 190 million gallons of wastewater per day.

CIWMB - California Integrated Waste Management Board

EDF - Environmental Defense Fund, a leading non-profit organization, represents 300,000 members nationwide, more than 55,000 of whom live in California. EDF links science, economics, and law to create innovative, economically viable solutions to today's environmental problems. EDF has participated in California energy policy issues since 1975.

ETDD Staff - Energy Technology Development Division Staff, California Energy Commission

GEA - The Geothermal Energy Association has approximately 40 members representing all of the geothermal energy producers and many of the service companies operating in the geothermal industry in California.

Genesis Energy Systems

IEM - Institute for Environmental Management

IEP - The Independent Energy Producers Association is California's oldest and leading trade association representing the interests of developers and operators of independent energy facilities, as well as independent power marketers. IEP's primary goals are to safeguard the interests of operating independent energy projects, and ensure that California remains a healthy market for development in the independent energy industry.

IPT - International Power Technology

LACSD - Los Angeles County Sanitation Districts: The districts operate and maintain both a regional wastewater and solid waste management system which provides services to voer 5 million people in Los Angeles county.

Laidlaw Gas Recovery Systems, Inc.: A wholly owned subsidiary of Laidlaw, Inc., a publicly traded company on the New York Stock Exchange. Laidlaw Gas Recovery Systems was founded in 1979 and currently owns and operates 12 landfill gas-to-energy facilities generating 43,000kW of electrical energy.

LES - Landfill Energy Systems presently has 10 landfill gas-fired power projects which produce over 40 MW in the U.S. California projects include an operating plant in Sonoma County and a plant under construction for the City of Sacramento.

MRWMD - Monterey Regional Waste Management District

NCPA - Northern California Power Agency

NEO Corp.

NRDC - Natural Resources Defense Counsel

Orange County

PG&E - Pacific Gas & Electric Company is a California Investor Owned Utility Company. PG&E provides gas and electric service to more than 13 million people in northern and central California.

SAIC- Science Applications International Corporation, Material and Structures Division is a 25 kW Solar Dish/Stirling developer, based in San Diego. As part of the United States Department of Energy Dish/Stirling Utility Joint Venture Program, the SAIC team is providing $18M of the $36M needed to field 50 systems in Southern California to capture a stake in the solar power thermal international market.

SCE - Southern California Edison is the nation's second largest electric utility, based on number of customers. The 109-year old investor owned utility serves more than 4.2 million customers in Central and Southern California. The utility's 50,000 square-mile service territory has a population of more than 11 million.

SDG&E - San Diego Gas & Electric Company, a subsidiary of Enova Corporation, is a California Investor Owned Utility Company founded in 1881. SDG&E provides service to 1.15 million electric customers in San Diego and southern Orange Counties, and gas service to 0.7 million customers in San Diego County.

SEIA - Solar Energy Industries Association

SMUD - Sacramento Municipal Utility District

Sonoma County - County landfill that provides disposal service for 425,000 residents and produces 6 MW of electricity from landfill gas.

STEA - The Solar Thermal Energy Alliance represent all nine of the operating solar thermal power plants in California.

SWANA - Solid Waste Association of North America has 5800 members and 44 chapters to serve the solid waste professional.

UCS - The Union of Concerned Scientists is an independent nonprofit public interest organization which works on issues where science and technology play a critical role. UCS has 100,000 sponsors nationwide, including 13,000 in California.

B. OTHER PARTICIPATING ORGANIZATIONS

[These are organizations whose representatives have attended at least one working group meeting]

Bechtel
BFP - Burney Forest Products
Byrne Associates
Calpine Corporation
CEERT - Center for Energy Efficiency and Renewable Technologies
City of Palo Alto
Consumers Utility Brokerage Inc.

Corporation for Solar Technology & Renewable Resources
County of Sacramento
CPUC/DRA - California Public Utilities Commission/Division of Ratepayer Advocates
Cummins Power Generation
EF&RAD Staff - Energy Forecasting and Resource Assessment Division Staff, California Energy Commission
ESI Energy, Inc.
Exergy, Inc.
FRA - Future Resource Associates Inc.
IPP - Independent Power Providers
KJC CC - KJC Consulting Company
LBNL - Lawrence Berkeley National Laboratory
LADWP - Los Angeles Department of Water and Power
Pacific Energy Group
Pacific Lumber Company
Project Development
Royal Farms/Sharp Energy, Inc.
Sierra Club
SoCal Gas - Southern California Gas Company
Thermo Ecotek
UAE Energy Operations - United American Energy Operations Corporation
UC Berkeley
UC Energy Institute
WAPA - Western Area Power Administration
Yolo County Public Works
Zond Corporation